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NUREG-0781
Supplement No. 3

Safety Evaluation Report

related to the operation of South Texas Project, Units 1 and 2

ORIGINAL

Docket Nos. 50-498 and 50-499

Houston Lighting and Power Company

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

May 1987

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ABSTRACT

In April 1986 the staff of the Nuclear Regulatory Commission issued its Safety Evaluation Report (NUREG-0781) regarding the application of Houston Lighting and Power Company (applicant and agent for the owners) for a license to operate South Texas Project, Units 1 and 2 (Docket Nos. 50-498 and 50-499). The facility is located in Matagorda County, Texas, west of the Colorado River, 8 miles north-northwest of the town of Matagorda and about 89 miles southwest of Houston. The first supplement to NUREG-0781 was issued in September 1986. The second supplement was issued in January 1987. This third supplement reports on the status of unresolved items in the Safety Evaluation Report and identifies certain additional items that have since been reviewed by the staff.

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1 INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

1.1 Introduction

In April 1986 the Nuclear Regulatory Commission (NRC) staff issued its Safety Evaluation Report (SER) (NUREG-0781) on the application filed by Houston Lighting and Power Company (HL&P), the applicant, acting on behalf of itself and the other owners [City Public Service Board of San Antonio (CPS), Central Power and Light Company (CPL), and City of Austin (COA)] for a license to operate South Texas Project, Units 1 and 2, Docket Nos. 50-498 and 50-499. At that time the staff identified items that had not been resolved with the applicant. In the first supplement to the SER (SSER 1) published in September 1986, the status of unresolved items and the comments made by the Advisory Committee on Reactor Safeguards in its letter dated June 10, 1986, were presented. The second supplement (SSER 2) reported on the status of the unresolved items and indicated those which had been resolved. This third supplement reports on the continuing process of resolving the remaining items.

Each of the following sections or appendices is numbered the same as the corresponding SER section or appendix that is being supplemented. Each section is supplementary to and not in lieu of the discussion in the SER unless otherwise noted. Appendix A continues the chronology of the staff's actions related to the processing of the South Texas Project application. Appendix B lists references cited in this report.* Appendix D contains abbreviations used in this supplement. Appendix E lists principal staff members and consultants who contributed to this supplement. Appendix V is the evaluation of relief requests from the American Society of Mechanical Engineers Boiler and Pressure Vessel Code under 10 CFR 50.55(a).

Copies of this SER supplement are available for inspection at the NRC Public Document Room at 1717 H Street, N.W., Washington, D.C., and at the local Public Document Room located at the Wharton Junior College Library, Wharton, Texas.

The NRC Project Manager for South Texas Project, Units 1 and 2, is N. Prasad Kadambi. Dr. Kadambi may be contacted by calling (301) 492-9407 or by writing to the U.S. Nuclear Regulatory Commission, Washington, D.C. 20555.

1.7 Open Items

The staff identified certain open items in the SER listed in Table 1.4 that was updated in SSER 1 and SSER 2. The section number of the discussion is shown for reference. Table 1.4 keeps a running tally of the list so that the number shown increases with new items even as items are resolved as shown in the status column. Eight items have been resolved in SSER 3, four have been substantially resolved,

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and one has been converted to confirmatory status. Four items have been added to the list of open items; one (No. 20) was changed from a confirmatory item before it was resolved. The remaining three are concerns that came to light after SSER 2 was issued. Table 1.4 shows six open items which have not been completely resolved, although substantial progress has been made on all of them.

1.8 Confirmatory Items

The staff identified confirmatory items in the SER indicating additional information or review needed to confirm preliminary conclusions. The listing was shown in Table 1.5 and was updated in SSER 1 and SSER 2. It is also a running tally. Thirteen items have been resolved in this supplement (SSER 3), and six additional items (Nos. 46 through 51) have been added to the list. The tabulation shows 16 items remain to be resolved, with the resolution of all items expected in the next supplement to the SER.

1.9 License Conditions

In Section 1.9 of the SER, the staff identified three license conditions. These are issues that must be resolved by the applicant as a condition for issuance of an operating license to ensure that NRC requirements are met during plant operation.

The current status of license conditions is listed in the updated version of Table 1.6. The item on qualification of the residual heat removal system has been resolved through a commitment made by the applicant in a submittal dated September 30, 1986, that the system would be qualified to withstand postaccident conditions. One new license condition has been added to reflect the incorporation of the accepted security plan into the license.

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Table 1.4 Listing of open items

Item		Status	SER Section
(1)	Internal flooding analysis	Resolved in SSER 3	3.4.1, 9.2.7, 9.3.3
(2)	Internal missiles analysis	Resolved in SSER 1	3.5.1, 10.4.9
(3)	Staff review of jet impingement from high energy pipe failures	Resolved in SSER 1	3.6.1
(4)	Equipment qualification		
	(a) Seismic and dynamic qual.	Converted to Confirmatory Item 46	3.10.1
	(b) Pump and valve operability	Converted to Confirmatory Item 47	3.10.2
	(c) Environmental equipment qual.	Converted to Confirmatory Item 48	3.11.3
(5)	Preservice inspection/inservice inspection program review	Resolved in SSER 3, except for new exemption	5.2.4, 6.6.1
(6)	Design, verification, and validation of qualified display processing system	Resolved in SSER 3 with two exceptions	7.1.2
(7)	Acceptability of isolation between safety and non-safety systems	Resolved in SSER 3	7.3.2.5
(8)	Conformance to RG 1.97	Resolved in SSER 2	7.5.2.4
(9)	Test results of aluminum-sheathed and copper-sheathed cable	Resolved in SSER 3	8.3.3.3
(10)	Maximum available fault currents at electrical penetrations	Resolved in SSER 1	8.3.3.5
(11)	Safe and alternate shutdown systems	Resolved in SSER 2	9.5.1
(12)	Auxiliary feedwater system reliability study	Resolved in SSER 1	10.4.9
(13)	Emergency planning	Resolved in SSER 3	13.3
(14)	Industrial security	Resolved in SSER 3	13.6
(15)	Analysis for boron dilution event during modes 4 and 5	Resolved in SSER 3	15.4.6

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Table 1.4 (Continued)

Item		Status	SER Section
(16)	Use of TREAT code for small-break loss-of-coolant-accident analysis	Resolved in SSER 3	15.6.5, 6.3.5
(17)	Review of submittals on Generic Letter 83-28	Converted to Confirmatory Item 44	15.8.2
(18)	Wear of the bottom mounted instrumentation thimbles	Converted to Confirmatory Item 45	3.9.2.3
(19)	Pipe break criteria	Resolved in SSER 3 with exception of exemption request	3.6.2
(20)	Inservice inspection and testing of emergency dc lighting	Resolved in SSER 3	9.5.3
(21)	Containment isolation of RCFC CCW line	Awaiting information	6.2.4
(22)	Sondex decommissioning	Under review	2.4
(23)	Containment purge actuation	Awaiting information	6.2.4

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Table 1.5 Listing of confirmatory items

Item		Status	SER Section
(1)	Onsite meteorological measurements program (a) Comparison of new with old system (b) Measurements of precipitation to resolve anomalous and inconsistent records	Under review	2.3.3
(2)	Staff's independent analysis of the thermal performance of the essential cooling pond	Resolved in SSER 1	2.4.11.2
(3)	Geotechnical monitoring program to detect horizontal and vertical movements	Resolved in SSER 1	2.5.1
(4)	Review of stability and safety data relative to main cooling reservoir dike after filling to 49 feet msl	Awaiting information	2.5.7
(5)	Completion of review of reports on pressure relief devices	Awaiting information	3.9.3.2
(6)	Design information on ASME Code Class 1, 2, and 3 component supports (Question 210.60)	Resolved in SSER 3	3.9.3.3
(7)	Preservice and inservice testing of pumps and valves	Resolved in SSER 2	3.9.6
(8)	Acceptability of consequences from momentary liftoff of fuel assembly	Resolved in SSER 1	4.2.3.1(9)
(9)	Combined seismic and loss-of-coolant-accident loads on fuel assemblies	Resolved in SSER 2	4.2.3.3(4)
(10)	Steam generator inspection	Resolved in SSER 3	5.4.2.2.2
(11)	Applicability of Diablo Canyon natural circulation test	Resolved in SSER 3	5.4.7
(12)	Conservatism of loss-of-coolant-accident analysis in light of information in FSAR Table 6.3.1 and response to Question 440.39	Resolved in SSER 1	6.3.1

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Table 1.5 (Continued)

Item		Status	SER Section
(13)	Analysis for nonisolable small-break loss-of-coolant accident	Combined with Open Item 16	6.3.5.2
(14)	Reanalysis of loss-of-coolant accident during shutdown	Combined with Confirmatory Item 15	6.3.5.3
(15)	Analyses for 6-inch and 8-inch breaks with justification for operator actions	Under review	6.3.6, 15.6.5
(16)	Interface between Class 1E and circuits	Under review	7.3.2.12
(17)	Adequacy of design change so that main steam isolation valves do not operate on safety injection signal	Resolved in SSER 3	7.3.2.2
(18)	Additional information on Criterion 2 of NUREG-0737 Item II.B.3	Resolved in SSER 2	9.3.2.2
(19)	Procedures for preventive maintenance and operability checks on emergency communication equipment	Under review	9.5.2.5
(20)	Inservice inspection and testing of emergency dc lighting	Converted to Open Item 20	9.5.3
(21)	Revision of radwaste process control program to meet staff guidelines	Under review	11.4.2
(22)	Update process and instrumentation diagrams for solid waste processing	Under review	11.4.2
(23)	Report on staff's site visit to corporate office and plant	Resolved in SSER 3	13.1.1.3
(24)	Conformance to Generic Letter 84-16 on hot operating experience	Resolved in SSER 3	13.1.2.1
(25)	Compliance with commitments on administrative procedures	Resolved in SSER 3	13.5.1.9

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Table 1.5 (Continued)

Item		Status	SER Section
(26)	Qualification requirements for preoperational and initial startup test personnel to be equivalent to American National Standards Institute/American Nuclear Society Standard 3.1-1981	Resolved in SSER 1	13.5.1.9
(27)	Staff review of the procedures generation package	Under review	13.5.2
(28)	Plant-specific information on steam generator tube rupture	Under review	15.6.3
(29)	Review of design against 10 CFR 50.62	Resolved in SSER 2	15.8.1
(30)	Results of the engineering assurance program	Awaiting information	17.4.3
(31)	Results of the final verification and validation program for the final emergency operating procedures	Under review	18
(32)	Results of investigation of green Roto-tellite lights under actual operating conditions	Under review	18
(33)	Results of surveys of lighting, sound, meter, and communication system when control room work is completed	Under review	18
(34)	NUREG-0737 items:		
	II.E.1.1 Auxiliary feedwater system evaluation	Combined with Open Item 12	10.4.9
	II.E.3.1 Emergency power for pressurizer heaters	Resolved in SSER 1	8.3.6
	II.G.1 Power supplies for pressurizer relief valves, block valves, and level indicators	Resolved in SSER 1	8.3.6
	II.K.1 IE Bulletins	Resolved in SSER 1	6.3.1
	5. Review of ESF Valves	Resolved in SSER 1	
	10. Operability Status		

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Table 1.5 (Continued)

Item			Status	SER Section
(34)	NUREG-0737 items: (cont'd)			
	II.K.2	Orders B&W plants 13. Thermal mechanical report: effect of HPI for small-break LOCA with no auxiliary feedwater	Resolved in SSER 1	15.6.5
	II.K.3	Final recommendations, B&O task force		
		3. Reporting SV and RV failures and challenges	Resolved in SSER 1	5.2.2.1
		5. Automatic trip of RCPs	Combined with Confirmatory Item 35	15.6.5.1
		17. ECCS outages	Resolved in SSER 1	6.3.1
		25. Power on pump seals	Resolved in SSER 1	15.1.15.1
		30. Small-break LOCA methods	Resolved in SSER 3	15.6.5
		31. Compliance with 10 CFR 50.46	Resolved in SSER 3	15.6.5
	III.A.1.2	Upgrading of emergency support facilities	Combined with Open Item 13	13.3
	III.A.2	Emergency preparedness	Combined with Open Item 13	13.3
	III.D.1.1	Primary coolant outside containment	Resolved in SSER 2 with a condition	13.5
(35)	Compliance with Generic Letter 85-12 (TMI Item II.K.3.5) RCP setpoint for small-break LOCAs		Resolved in SSER 3	15.6.5.1
(36)	Safety-Related Instrument Tubing Program		Resolved in SSER 2	3.9.3
(37)	DG Fuel Oil Piping Vibration Test Plan		Resolved in SSER 2	3.9.2.1
(38)	(a) Instrumentation and control systems audit		Under review	7.1
	(b) Electrical systems audit		Resolved in SSER 3 with two exceptions	8.1
(39)	SPDS audit		Under review	9.5.1

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Table 1.5 (Continued)

Item		Status	SER Section
(40)	Fire Protection Program audit	Resolved in SSER 3	9.5.1
(41)	Deletion of the containment spray system sump additive tank	Resolved in SSER 2, generic issue under review	6.5.2
(42)	RTD bypass loop elimination	Resolved in SSER 2	4.4.3.2
(43)	Revision to the BART code	Resolved in SSER 3	6.3.5
(44)	Compliance with Generic Letter 83-28	Resolved in SSER 2, items under review do not impact licensing	15.8.2
(45)	BMI thimble vibration	Awaiting information	
(46)	Seismic and dynamic qualification audit	Action items identified in SSER 3	3.10.1
(47)	Pump and valve operability	Action items identified in SSER 3	3.10.2
(48)	Environmental equipment qualification	Under review	3.11.1
(49)	Attachment of safety-related components to non-safety-related frames	Under review	3.2
(50)	Conformance to Branch Technical Position PSB-1	Awaiting information	8.1
(51)	RCFC differential pressure switch downgrade	Under review	7.5.2.4

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Table 1.6 Listing of license conditions

Item		Status	SER Section
(1)	Implementation report on preoperational testing of the reactor vessel water level system	Under review	4.4.6.3
(2)	Postaccident qualification of the residual heat removal system before December 31, 1988, or the second refueling outage, whichever comes first	Resolved through commitment made September 20, 1986	15.6.5.1.2
(3)	Implementation and maintenance in effect of all provisions of the approved fire protection program	Resolved in SSER 3	9.5.1.8
(4)	Implementation and maintenance in effect of all provisions of the physical security, guard training and qualification, and safeguards contingency plans	Resolved in SSER 3	13.6.1

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3 DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

3.4 Water Level (Flood) Design

3.4.1 Flood Protection

Open Item 1 regarding the need for an internal flooding analysis is discussed in SER Sections 3.4.1, 3.6.1, 9.2.7, and 9.3.3 and is based on the incompleteness of the applicant's internal flooding analysis in order to ensure proper protection of safety-related equipment from flooding. In SER Section 3.4.1, the staff identified flooding concerns associated with leakage resulting from failure of tanks. In Section 3.6.1 in the SER and Section 3.6.1 in SSER 1, the staff discussed protection against flooding effects resulting from high- and moderate-energy piping systems outside the containment. In SER Section 9.2.7, the staff identified a specific concern related to flooding of both reactor water makeup pumps resulting from failure of non-safety-related equipment and/or piping. Finally, in SER Section 9.3.3, the staff identified another specific concern related to the possible flooding of the auxiliary feedwater (AFW) pump cubicles resulting from rainfall associated with tornadoes.

By letter dated November 3, 1986, the applicant provided the results of the internal flooding analysis which covered all of the issues identified in Open Item 1. The applicant stated that, except for the detailed analysis of the makeup water pump room, the results of the flooding analysis will be included in the FSAR. The makeup water pump room analysis, Enclosure 2 to the November 3, 1986 letter, will not be incorporated into the Final Safety Analysis Report (FSAR) but will be kept on file with the detailed room-specific flooding analyses for the rest of the plant. The results of the analysis are discussed in FSAR Section 9.2.7.

In SER Section 9.2.7, the staff identified a flooding concern associated with the reactor makeup water (RMW) system. Portions of the RMW system including the RMW pumps are safety related in that the system provides an assured source of water to the spent fuel pool and the component cooling water (CCW) system. However, both pumps are in the same compartment as that in which the RMW storage tank is located, and the staff expressed a concern that failure of non-safety-related equipment and/or piping in this room could cause flooding of both pumps during and/or following a seismic event. The applicant analyzed this event and identified alternative methods for providing makeup to the spent fuel pool. The CCW system is seismic Category I and, therefore, does not require a seismic makeup system. Leakage from the CCW system is considered to be insignificant following a seismic event. The spent fuel pool cooling system is also seismic Category I, but a seismic Category I makeup source is still required to make up for leakage and evaporative losses. If the RMW pumps are not available following a seismic event, makeup can be added to the spent fuel pool via hoses from a connection on the essential service water system. The essential service water system will, therefore, act as the assured source of makeup water to the spent fuel pool following a seismic event.

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In SER Section 9.3.3, the staff reported that the applicant will perform an analysis and provide additional curbs and elevated thresholds as necessary to preclude unacceptable consequences resulting from internal flooding from rainfall associated with tornadoes because of the liftoff and/or vent panel design on the isolation valve cubicles. The applicant has completed the analysis and provided the results in the November 3, 1986 letter. The applicant indicated that the results will be incorporated into FSAR Section 3.4.4. Additional curbs have been provided to channel rainwater away from the AFW pump cubicles. The floor drains in the areas directly above the pump cubicles will be capped to prevent rainwater from entering them. The flooding analysis was used to determine the sizing of the curbs and also resulted in capping of the floor drains. The staff expressed a concern related to maintaining the caps in place for the life of the plant. As a result of this concern, the applicant proposed to weld the caps in place. The staff concluded that this was an acceptable method of providing flood protection for this area.

For areas where redundant water level indications are not available for the detection of flooding resulting from a piping failure, regular inspections during normal operation are being implemented. The staff requested further information regarding these inspections (walkdowns) to ensure adequate flood detection and protection were provided. The walkdowns for flood detection are being implemented for the common area north of the AFW pump room and the tendon access gallery.

The common area north of the AFW pump room has a single level switch and a local level alarm for indication of flooding within the area. Therefore, flooding in this area will not be alarmed in the control room. The only source of flooding to this area that could go undetected for a significant time is from the fire protection system. Leakage flowrates greater than 30 gpm, which includes leakage from a "critical crack," will be detected because the leakage will cause the main fire pumps to automatically start. For small leakages of less than 30 gpm, the loss of water might go undetected because the fire jockey pump could maintain fire protection system pressure. However, because of the low crack flowrate, the flood level in the area will not reach an unacceptable level that could threaten safety-related components for at least 52 hours (based on a crack flow of 30 gpm). The staff agrees with the applicant's conclusion that because the area is inspected regularly during normal operation (approximately once every shift), such small cracks will be detected long before flooding reaches an unacceptable level.

The tendon access gallery has a sump equipped with a non-safety-related level switch and local alarm. Therefore, flooding in this area will not be alarmed in the control room. The sources of flooding in this area are limited to a 2-in. potable water line used for sump pump testing and the electrical auxiliary building (EAB) floor drain lines which empty into this area. There is no safety-related equipment in the area. It would take at least 7 days to fill the area from a leakage crack in the potable water line. Flooding due to a complete break in the potable water line is detectable because of the continuous use of the potable water system. It is only the small leak rates that are not readily detectable. Significant discharge of water from the EAB floor drains is possible in the case of a moderate-energy leakage crack or fire in the EAB. These sources are detectable and isolable in the EAB. However, given the large volume of the tendon access gallery (730,000 cubic feet), the staff concludes that flooding from small leak rates will be detected by walkdowns which by

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procedure will be performed at no more than 28-hour intervals. These surveillance intervals will ensure detection before the gallery overflows to other areas containing safety-related equipment.

In addition, water level instruments in certain areas of the mechanical auxiliary building (MAB) are not seismically qualified and walkdowns for flood detection are being procedurally implemented following a seismic event. The maximum interval between these walkdowns is 2 hours, which was determined to be adequate to protect essential equipment from any flooding source. The walkdowns would continue until adequate level indication and alarms for flood detection were shown to be functional. The staff concludes that the post-seismic walkdowns that will be procedurally implemented for specific areas to detect leakage are an adequate method of flood protection following a seismic event. The specific areas to be surveyed are the refueling water storage tank or reactor makeup water tank compartment, the recycle holdup tanks 1A and 1B compartments and the containment penetration area at elevation 10'-0" or any one of the areas containing MAB sumps 1 through 4. The use of the term "or" reflects the fact that the flooding source could be detected in either of the identified areas and the walkdown need only include one of the areas.

In summary, the staff concludes that the protection against internal flooding at South Texas Units 1 and 2 meets the requirements of General Design Criterion 4 with respect to protection from the flooding effects of postulated pipe breaks and other internal flooding sources and is, therefore, acceptable. The staff's conclusion is based on its determination that the South Texas design for flood protection meets the acceptance criteria of Standard Review Plan (SRP) Sections 3.4.1, 3.6.1, and 9.3.3 (NUREG-0800) as they relate to protection against internal flooding.

3.6 Protection Against Dynamic Effects Associated With the Postulated Rupture of Piping

3.6.2 Determination of Rupture Locations and Dynamic Effects Associated With the Postulated Rupture of Piping

In SSER 2, the staff identified four areas under the heading of pipe break criteria that were being reviewed to determine acceptability of granting relief in certain pipe break postulation and analysis criteria. These areas are:

(1) increasing the minimum acceptable value of the cumulative usage factor (CUF) from 0.1 to 0.4

(2) additional elimination of arbitrary intermediate breaks

(3) use of coupled analyses and increased seismic damping factors

(4) use of leak-before-break technology beyond the locations approved by the Commission's completed rulemaking (see 51 FR 12502).

In the matter of increasing the minimum acceptable value of CUF to 0.4, the staff concluded that a generic use of 0.4 is unacceptable. In a letter dated December 31, 1986, the staff informed the applicant that 40 specific breaks in

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the pressurizer surge line and the safety injection lines need not be postulated although the CUF values exceeded 0.1.

In the matter of the coupled analysis, the staff concluded that piping 12 in. and larger connected to the reactor coolant loop may be modeled in the same piping analysis and, therefore, may be considered as part of the main run. The staff found acceptable the proposal by the applicant in the submittal dated October 10, 1986. However, the part of the submittal that was related to the use of increased seismic damping factors was subjected to further review and the conclusions are provided in Section 3.9.2.2.

3.6.2.1 Additional Arbitrary Intermediate Breaks

In Appendix G to the SER, the staff evaluated the applicant's request to eliminate arbitrary intermediate pipe breaks. Subsequently, in a letter dated August 28, 1986, the applicant requested staff approval to revise its previous commitment to control the location of welded attachments in the vicinity of arbitrary intermediate break (AIB) locations and to eliminate AIBs in additional piping lines that had not been identified previously.

The applicant stated that rather than controlling the locations of welded attachments with respect to AIB locations, it is evaluating the fatigue effects at welded attachments in American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) Class 2 and 3 piping systems in accordance with Paragraph NC/ND-3645 of the ASME Code, Section III, and ASME Code Cases N-122, N-391, and N-318-2 The welded attachments in the main steam, feedwater, and auxiliary feedwater system with the most severe loadings--determined from a primary plus secondary stress and fatigue evaluation--are assessed for large, unanticipated dynamic loads such as those resulting from steam or waterhammer. The applicant will assess the weak link in the piping-to-pipe-support load path and ensure that under such loading conditions the integrity of the piping pressure will remain intact. The results of the assessment will be provided to the staff for review before start of low-power testing. In addition, during ongoing and future design work, any relocations of, modifications to, or additions of welded attachments to the piping systems in which AIBs are eliminated should be reviewed by the staff to ensure that the enveloping assessments described above still provide adequate protection against pipe breaks resulting from high local stresses due to welded attachments.

As stated in Appendix G to the SER, should other piping lines that are not specifically identified in the applicant's submittals subsequently qualify for the conditions described therein, the AIB elimination criteria may be used provided the additional piping lines are appropriately identified to the staff. Accordingly, all piping lines for which AIBs are or will be eliminated shall be identified in the FSAR to ensure that a complete and documented list is available for staff review, and a specific request for prior approval will not be necessary.

On the basis of the above discussion, the staff approves the elimination of AIBs in those piping lines identified by the applicant to date, which satisfies the AIB elimination criteria described in Appendix G to the SER and as revised in the applicant's letter of August 28, 1986. The applicant has provided adequate

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measures to minimize the potential for pipe failures to occur at welded attachments near locations where AIBs will be eliminated in those piping systems subject to fatigue and large unanticipated dynamic loads. The staff finds that the applicant's submittal provides a level of safety equivalent to that specified in the SRP (NUREG-0800) and is thus acceptable and can be implemented without undue risk to the health and safety of the public.

3.8 Design of Seismic Category I Structures

3.8.6 Structural Audit

By letter dated March 11, 1987, the applicant informed the staff of substantive changes to be made to FSAR Sections 3.8.4 and 3.8.5. These changes concerned the structural analyses, methodologies, and computer codes used in the design of Category I structures. The original text of the FSAR, which was reviewed and accepted by the staff, described the methodologies and computer codes used by the previous architect-engineer (AE) in the structural analysis of Category I structures. During the applicant's transition period from the previous AE firm to the current AE firm, the calculations were reviewed for completeness and acceptability. This review by the applicant and the current AE indicated that the existing calculations were either incomplete or acceptable subject to independent confirmatory calculations. Once the status of the existing calculations was determined, the applicant's AE proceeded to complete the calculations and to perform the necessary confirmatory calculations to ensure that the commitments made in the FSAR were satisfied. On the basis of the applicant's review and the confirmatory calculations performed by the applicant's AE, the applicant has indicated that the design basis and other commitments made in the FSAR remain valid.

The applicant's changes to the structural analysis methodologies and computer codes are summarized as follows:

(1) utilization of conventional analyses for column and beams as well as three-dimensional finite element modeling of slabs and shear walls in lieu of the two-dimensional frame models used by the previous AE

(2) selection and modeling of shear walls according to their continuity between floor levels and in proportion to their relative stiffness

(3) utilization of two-dimensional finite element modeling of foundation basements, which included the modeling of the walls, in lieu of the plane grids of beams used by the previous AE

(4) listing of the computer program BSAP instead of the program STRUDL-II used by the previous AE

These changes did not result in modifications to Category I structures in place at the time the applicant changed AE firms.

To verify the applicant's conclusion that these changes did not affect the design basis and other commitments made in the FSAR, the staff conducted a review of sample calculations in Bethesda, Maryland on March 30, 1987. The calculations reviewed included portions of the mechanical-electrical building,

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reactor containment building, reactor building internal structures, and the isolation valve cubicle. These calculations indicated that the required margins in structural stresses and bending moments of critical sections were obtained with respect to capacities. The calculations reviewed by the staff were representative of the changes that were the subject of the applicant's March 11, 1987 letter. The structural analyses and methodologies used in these calculations were consistent with conventional analysis practice.

On the basis of this review, the staff concludes that the structural analyses, methodologies, and computer codes used by the current AE, as identified by the applicant's March 11, 1987 letter, are acceptable. In addition, the conclusions reached by the staff in the SER remain valid.

3.9 Mechanical Systems and Components

3.9.2 Dynamic Testing and Analysis of Systems, Components, and Equipment

3.9.2.2 Seismic Subsystem Analysis

In Section 3.6.2 of SSER 2, the staff stated that the issue of increased damping values used in piping seismic analyses is part of Open Item 19, "Pipe Break Criteria."

The staff first became aware of this issue as a result of a letter from the applicant dated October 10, 1986, which stated that some piping seismic analyses for South Texas Units 1 and 2 had used the multiple support input response spectra method (MRS) with combination of support groups by the absolute sum method together with the increased damping values from ASME Code Case N-411, "Alternate Damping Values for Seismic Analysis of Classes 1, 2 and 3 Piping Sections, Section III, Division 1." In two earlier evaluations, the staff had approved the use of the MRS methodology and N-411 methodology for South Texas Units 1 and 2. However, until receipt of the October 10, 1986 letter, the use of MRS in conjunction with N-411 methodology in the same analysis was never explicitly approved by the staff for South Texas.

The current staff position on this issue is that damping values from Code Case N-411 may be used only in analyses that assume an upper bound envelope of the individual response spectra for all support locations to calculate maximum inertial response of multiply supported items. The basis for this position is documented in Regulatory Guide 1.84, "Design and Fabrication Code Case Acceptability--ASME Section III, Division 1," Revision 24, dated June 1986. This revision states that Code Case N-411 is acceptable provided the use of the damping values in the code case is limited only to response spectrum analyses similar to the analysis used in NUREG/CR-3526, "Impact of Changes in Damping and Spectrum Peak Broadening on the Seismic Response of Piping Systems." An upper bound envelope response spectrum, as indicated in SRP Section 3.9.2, was used as input to the piping system analyses that are discussed in NUREG/CR-3526.

The above staff position was transmitted to the applicant in a letter dated January 16, 1987. In this letter, the staff requested that the applicant provide study calculations using either of the following staff-approved methodologies to demonstrate that the use of MRS plus N-411 methodology is equally as conservative as the staff position:

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(1) Use the multiple support input response spectra method with combination of support groups by the absolute sum method together with values from Regulatory Guide 1.61 damping.

(2) Use the upper bound envelope response spectra method together with Code Case N-411 damping values.

In a letter dated March 9, 1987, the applicant submitted the final response to the staff's questions. This response is summarized below.

MRS in conjunction with N-411 methodology was used for final South Texas Units 1 and 2 piping seismic stress analyses in 57 balance-of-plant ASME Code Class 1, 2 and 3 piping stress calculations encompassing 1915 large- and small-bore pipe supports. In these 57 piping stress calculations, 12 plant process systems are partially or totally included. To adequately encompass the numerous characteristics of the specific piping system designs contained in the 57 ASME MRS in conjunction with N-411 piping stress calculations, the following criteria were established for inclusion within the scope of the study calculations:

(1) Include a significant number of piping stress calculations in the study base relative to the total number of piping stress calculations that utilized MRS in conjunction with N-411 methodology.

(2) Include all 12 plant systems for which MRS in conjunction with N-411 methodology was used.

(3) Include all piping sizes (nominal diameter) for which MRS in conjunction with N-411 methodology was used.

(4) Include piping stress analyses for all plant buildings for which MRS in conjunction with N-411 methodology was used.

(5) Include piping runs for which MRS in conjunction with N-411 methodology was used that encompass, to the extent possible, those plant elevations where piping runs traverse both horizontally and vertically through the plant buildings.

(6) Include all pipe support types for which MRS in conjunction with N-411 methodology was used.

Criterion (1) above was satisfied by selecting 18 (31%) of the 57 applicable analyses for reanalysis using both of the staff-approved methodologies and acceptable FSAR load combinations and stress limits. As discussed in the study calculation summary report that was attached to the March 9, 1987 letter, Criteria (2) through (6) were also adequately satisfied in these reanalyses.

The study calculation results show that piping stresses and pipe support designs meet Code-allowable stress criteria when at least one of the two staff-approved methodologies is used and that changes in available design margins from one methodology to another are inconsequentially small relative to the available design margins in the existing plant design. Line-mounted components (valves, etc.) remain qualified for the calculated changes in excitation level determined using the two staff-approved methodologies. Calculated nozzle loads remain within vendor acceptable limits. All pipe break postulation criteria have been met; no changes to current postulated pipe break locations in the plant design

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occur. Leak-before-break (LBB) analyses (crack stability studies) were reexamined, and required margins are maintained and previous LBB conclusions regarding crack propagation being mitigated remain valid. No hardware modifications to the existing plant were necessary.

On the basis of the above discussion, the staff concludes that a reanalysis program that included 31% of the 57 applicable calculations of record and also included the large number of variables encompassed by Criteria (2) through (6) above provides reasonable assurance that the average margins for those calculations of record for which no study calculations were performed are within the same range as the average margin of the 18 study calculations. Since the study calculations revealed that there was very little change in design margin from one methodology to another, the staff also concludes that the current 57 design-basis record calculations that use MRS in conjunction with N-411 methodology can remain unchanged with no effect on public health and safety. The applicant has stated that future piping stress analyses will utilize one of the staff-approved methodologies.

3.9.3 ASME Code Class 1, 2, and 3 Components, Component Supports, and Core Support Structures

3.9.3.3 Component Supports

In the SER, the staff stated that it required more information about the design of nuclear steam supply system (NSSS) ASME Code Class 1, 2, and 3 component supports. This was identified as Confirmatory Item 6. In a letter dated March 2, 1987, the applicant provided this information in the form of a revised response to FSAR Question 210.60N. This question contained the staff position that, for the design of component supports, the stresses produced by seismic anchor point motion of piping and the thermal expansion of piping should be categorized as primary stresses. In the letter of March 2, 1987, the applicant stated that the NSSS component supports have been evaluated for compliance with this position and are acceptable; that is, the total stresses are all below the allowable stresses in ASME Code Section III, Subsection NF, "Component Supports." The applicant stated that this revised response to Question 210.60N will be incorporated into a future FSAR amendment.

On the basis of the above information, the staff concludes that the design criteria for NSSS component supports are acceptable and that Confirmatory Item 6 is resolved.

3.10 Seismic and Dynamic Qualification of Safety-Related Mechanical and Electrical Equipment

3.10.1 Seismic and Dynamic Qualification

3.10.1.1 Introduction

Evaluation of the applicant's program for seismic and dynamic qualification of safety-related electrical and mechanical equipment consists of (1) a determination of the acceptability of the procedures used, the standards followed, and the completeness of the program in general and (2) an audit of selected equipment items to develop a basis for judging the completeness and adequacy of the implementation of the entire seismic and dynamic qualification program.

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Guidance for the evaluation is provided by SRP Section 3.10 and its ancillary documents, Regulatory Guides (RGs) 1.61, 1.89, 1.92, and 1.100, NUREG-0484, and Institute of Electrical and Electronics Engineers (IEEE) Standards 344-1975 and 323-1974. These documents define acceptable methodologies for the seismic qualification of equipment. Conformance with these criteria is sufficient to satisfy the applicable portions of General Design Criteria (GDC) 1, 2, 4, 14, and 30 of Appendix A to Part 50 of Title 10 of the Code of Federal Regulations (10 CFR 50), as well as Appendix B to 10 CFR 50, and Appendix A to 10 CFR 100. A Seismic Qualification Review Team (SQRT), which consisted of staff engineers and staff consultants from the Idaho National Engineering Laboratory (INEL, EG&G Idaho), evaluated the program for South Texas Unit 1.

3.10.1.2 Discussion

The SQRT reviewed the equipment dynamic qualification information contained in FSAR Sections 3.9.2 and 3.10 and visited the site from December 16 through December 19, 1986 to determine the extent to which the qualification of the equipment, as installed at South Texas Unit 1, meets the criteria described above. A representative sample of safety-related electrical and mechanical equipment, as well as instrumentation, included in both the nuclear steam supply system (NSSS) and balance of plant (BOP) scopes, was selected for the audit. Table 3.1 identifies the equipment audited. The site visit consisted of field observations of the actual, final equipment configuration and its installation. This was followed by a review of the corresponding design specifications, tests, and/or analysis qualification documents which the applicant maintains in its central files. Observing the field installation of the equipment is necessary to verify and validate equipment modeling employed in the qualification program. In addition to the document reviews and equipment inspections, the applicant made summary presentations of the maintenance, startup testing, and inservice inspection programs.

The audit identified both plant generic and equipment-specific concerns, which are shown below as action items requiring additional submittals by the applicant. The issues and their disposition, if any, are summarized in the following sections and Table 3.1.

3.10.1.3 Generic Items

(1) The applicant is to confirm the completion of the seismic qualification program with special emphasis on the in-progress or incomplete items as given in Table 3.1.

(2) The applicant is to confirm the completion of verification of as-built loads for pumps and valves.

The above two issues are confirmatory action items.

3.10.1.4 Equipment-Specific Items

(1) The review of the qualification document for the high head safety injection pump (NSSS-11) indicated that the report prepared by Nickerson Engineering was not reviewed by Westinghouse. Further, the details of the analysis and results were not in an auditable form within the time constraint of a

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site review. The problem was discussed with the applicant. Westinghouse will review the report and prepare an auditable summary. This summary will be forwarded to the SQRT for review. This is an action item.

(2) The qualification of the isolation/termination cabinet (BOP-1) is based on analysis. The analysis of this cabinet, reportedly, takes advantage of a resonance search test and analysis performed on another cabinet. This test cabinet was flexible. However, the isolation/termination cabinet at South Texas is a modified and strengthened version of the tested cabinet. The rigidity of the South Texas cabinet was established through analysis only. Neither a direct link between the field cabinet and the model authenticated cabinet exists, nor is the relative rigidity of the South Texas cabinet demonstrated independently by a test. All subsequent qualification and operability of the internal devices are predicated on this cabinet being rigid.

Under the circumstance, the rigidity of the cabinet should be established. This is an action item.

(3) The qualification review of the reactor coolant hot leg sample valve (BOP-8) indicated that the post-seismic check of the screws found them loosened during the test. Modifications to the valve to preclude the screws from loosening were recommended. Modifications have been made in the field. However, the maintenance and confirmatory check to confirm that screws remain tight after a seismic event has not been incorporated in the surveillance and maintenance manual. The staff should be informed that the requirements have been incorporated in the surveillance and maintenance program. This is a confirmatory action item that will be satisfied on appropriate notification.

(4) The as-built valve nozzle loads exceed those used in the testing. However, this concern will be resolved under generic action item 2.

(5) The review of the qualification for the instrument control room panel (BOP-11) indicates that the qualification and review by the BOP vendor for safety-related internal components is not complete. There are differences between devices tested and those installed, and the similarity for each piece has not yet been established. This deficiency may involve other panels. This also includes the evaluation of the qualified life-span of limited life components. Requalification efforts are, however, in progress. A satisfactory completion of these efforts including the incorporation of the resulting requirements in the surveillance and maintenance program is required. This is a confirmatory action item. The confirmation should include a list of the devices, if any, for which requalification was necessary.

3.10.1.5 Conclusion

On the basis of the observation of the field installation, review of the qualification documents, and responses provided by the applicant to SQRT's questions during the audit, the applicant's seismic and dynamic qualification program has been found to be well defined and adequately implemented. Once the issues identified in Sections 3.10.1.3 and 3.10.1.4 and Table 3.1 have been closed, the seismic and dynamic qualification of the safety-related equipment

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at South Texas Unit 1 will meet the applicable portions of GDC 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50, Appendix B to 10 CFR 50, and Appendix A to 10 CFR 100.

3.10.2 Pump and Valve Operability Assurance

3.10.2.1 Introduction

The staff performs a two-step review of each applicant's pump and valve operability assurance program to determine if the program can ensure that all pumps and valves important to safety will operate when required for the life of the plant under normal and accident conditions. The first step is a review of FSAR Section 3.9.3.2. However, this information is general in nature and lacks sufficient detail to determine the scope of the overall equipment qualification program as it pertains to pump and valve operability. The results of the FSAR evaluation appear in Section 3.10.2 of the SER. Any open SER issues are resolved before or concurrently with the onsite audit.

A Pump and Valve Operability Review Team (PVORT), consisting of engineers from the NRC staff and the Idaho National Engineering Laboratory (INEL, EG&G Idaho), conducted the second step of the review, which consisted of an audit of a representative sample of installed pump and valve assemblies and their supporting qualification documents at the plant site. On the basis of the results of both the audit and the FSAR review, the PVORT determines if the applicant's overall program conforms to the current licensing criteria in SRP Section 3.10. Conformance with SRP Section 3.10 criteria is required in order to satisfy the applicable portions of GDC 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50 as well as Appendix B to 10 CFR 50.

3.10.2.2 Discussion

The PVORT reviewed the pump and valve operability assurance information contained in FSAR Section 3.9.3.2 and later conducted an onsite audit to determine the extent to which the pumps and valves important to safety meet the criteria listed above. The issues that resulted from the FSAR evaluation appeared in the SER. Many of these issues were resolved by material submitted by the applicant up to and including FSAR Amendment 54. Additional qualification issues not covered in the SER were discussed at a preaudit meeting held on September 16, 1986. Several of these preaudit issues were adequately resolved by the applicant in a letter dated October 9, 1986. The remaining SER and preaudit issues were resolved during the site audit from December 16 through December 19, 1986.

The staff investigated the deep draft pump issue during the audit. In a letter dated October 9, 1986, the applicant indicated that the South Texas vertical pumps do not fall into the category of deep draft pumps. The program does meet the intent of the NRC and License Review Group-II guidelines with respect to long-term operation, vibration monitoring, maintenance, and inspection. On the basis of the applicant's response and site verification, the South Texas pump qualification program should be adequate to ensure operability of vertical pumps.

The staff requested information regarding operability of containment purge and vent valves in accordance with NUREG-0737, TMI Item II.E.4.2(6). In a letter

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dated October 9, 1986, the applicant responded to the request indicating that the containment purge and vent system has been revised to incorporate a pneumatic valve on the outboard side of the intake and exhaust lines. The applicant committed to provide documentation demonstrating valve operability before fuel load. The staff's position regarding operability of these valves will be included in a future supplement to the SER. This is an action item.

The remaining issues identified in the SER and how each issue was addressed are discussed below.

SER issues 1, 3, and 7 (b), (c), (d), and (e) were completely resolved by the applicant in FSAR Amendments 45 through 54. The staff has verified that the FSAR includes the appropriate tables and text description. Therefore, SER issues 1, 3, and 7 (b), (c), (d), and (e) are closed.

SER issues 5, 6, and 7 (a) and (f) were resolved and closed on the basis of the review of applicant responses, FSAR revisions, and/or site verification.

SER issues 2 and 4 are restated and their resolution is presented below:

(2) It is not clear that Table 3.9-1.2 (Amendment 44) is a complete list of active balance-of-plant (BOP) valves.

(a) BOP check valves have not been included in the table.

(b) Some valves listed in Table 3.9-1.2 no longer appear to be used. For example, containment purge valves HA002 and HA004, as well as radiation monitoring valves RP002 and RP005, have been deleted from Table 7.3-9 (Amendment 43).

(c) For all active BOP valves, the applicant should list the function, American Nuclear Society (ANS) safety class, and active status in a manner similar to the way Table 3.9-1.2A lists NSSS valves.

The three concerns originally identified as examples have been adequately resolved in revisions to the FSAR; however, other discrepancies were found during the site audit. This concern was transferred and combined into generic action item 3 and is explained further in Section 3.10.2.3.

(4) The applicant must clearly show the extent to which RG 1.148, ANSI/ASME N551.1 draft standards, and ANSI B16.41 are met.

During the site audit, the applicant provided a response to this concern. FSAR Table 3.9-23 (Amendment 54) describes compliance with RG 1.148. The FSAR information was found to be adequate and resolved the concern. The applicant did not address ANSI/ASME N551.1 and ANSI B16.41. This was found to be acceptable as N551.1 is a draft and a response is not required. ANSI B16.41 is a new standard, and the applicant has not been required to respond. Although the applicant's program does not meet the draft standard and the new B16.41 standard, the PVORT reviewed selected procurement specifications and maintenance programs during the site audit and found the applicant's program satisfactory. This issue is closed.

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3.10.2.3 Operability Issues

On the basis of the results of the PVORT site audit, the staff has identified to the applicant the following four equipment-specific and five generic action items. These issues must be resolved before fuel load.

Specific Action Items

(1) The site audit showed that the applicant had developed a design to minimize the effect of wet steam in the auxiliary feedwater pump. The design had not been tested at the time of the audit. The applicant committed to confirm when preoperational testing was satisfactorily completed, to identify all deficiencies discovered during testing, and to describe the disposition of the deficiencies.

(2) During the site audit, the applicant was asked to provide the preventive maintenance schedule for AF-0091 (auxiliary feedwater minimum flow recirculation valve). The maintenance schedule had not been developed. The applicant committed to provide evidence that manufacturer-recommended maintenance will be performed.

(3) The review of the boric acid transfer pump (tag number 3R171NPA103A) identified an apparent discrepancy in the level of radiation for which the equipment is qualified. The test sequence described in Westinghouse report WCAP-8687 (EQDP-AE-3) indicated 10000 R, but the qualification summary Table I in the same report showed 400 R. The PVORT questionnaire reported 2100 R. The applicant shall (a) modify the WCAP-8687 report and PVORT form to correct the apparent discrepancy in the qualified level of radiation and (b) confirm that the equipment qualification file has been supplemented with the appropriate documentation. This is an action item.

(4) The review of the boric acid transfer pump (tag number 3R171NPA103A) identified concerns regarding the qualification document file. The applicant claimed the equipment was fully qualified, but the documentation file did not reference operability of the motor at reduced voltages. The applicant shall (a) provide a copy of the test report that references operability of canned motors at reduced voltages, (b) describe the basis for similarity of the motor test results to the operation of the boric acid transfer pump used at South Texas, and (c) confirm that the equipment qualification file has been supplemented with the appropriate test data and required analyses. This is an action item.

Generic Action Items

(1) At the time of the audit, most construction tests had been completed. However, the hot functional tests were scheduled for January 1987. The applicant shall confirm that all preservice tests for safety-related pumps and valves that are required before fuel load have been completed. The applicant shall also provide a list of all preservice tests completed and the justification for any tests scheduled beyond fuel load. This is an action item.

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(2) At the time of the audit, approximately 10 to 15 percent of all safety-related pumps and valves had not been qualified. The applicant shall confirm that all safety-related pumps and valves are properly qualified and installed before fuel load. In addition, the applicant shall provide written confirmation that the original loads used in tests or analyses to qualify safety-related pumps and valves are not exceeded by any new loads, such as those imposed by a loss-of-coolant accident (hydrodynamic loads) or as-built conditions. This is an action item.

(3) At the conclusion of the PVORT audit, it was apparent that a complete list of safety-related pumps and valves had not been provided in the FSAR. The applicant shall confirm that all safety-related NSSS and BOP pumps and valves, including check valves, are correctly identified in the FSAR before fuel load. This is an action item.

(4) During the site audit, a nonconformance tag was found attached to a component 5 years after the nonconformance had been cleared. The applicant explained that the nonconformance was cleared during the transition of architect engineers from Brown and Root to Bechtel. As a result of the changeover, the tag was overlooked. This tag appeared to be an isolated case and, therefore, not an indication of a programmatic problem. However, the staff was concerned that a tag was attached for 5 years and no action had been taken. The applicant shall confirm that nonconformances issued for safety-related pumps and valves during the transition period have been reviewed and ensure that they have been properly picked up by a Bechtel program and dispositioned. This is an action item.

(5) The site audit showed that the applicant was using a 30-day postaccident operating time for qualifying equipment. Typically 100 days or more is used. The applicant shall provide information that demonstrates how a 100-day minimum postaccident operability time is met. This action item will be addressed in Section 3.11.3 of a future supplement.

The site audit results are summarized in Table 3.2

3.10.2.4 Conclusion

On the basis of the results of (1) the component walkdown and the review of the qualification document packages, (2) the additional explanations and information provided by the applicant throughout the audit, and (3) the resolution of the SER action items, the staff concludes that an appropriate pump and valve operability assurance program has been defined and implemented. The continuous implementation of this overall program should provide adequate assurance that all pumps and valves important to safety will perform their safety-related functions as required for the life of the plant. With the exception of the issues identified in Section 3.10.2.3, the staff concludes that the applicant has qualified those pumps and valves important to safety so as to meet the applicable portions of GDC 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50 and Appendix B to 10 CFR 50.

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Table 3.1 Equipment audited at South Texas

Number*	Equipment	Applicant ID number	Safety function	Findings	Resolution	Status
NSSS-1	Qualified display processing system electronics cabinet	4Z551ZLP677	Postaccident monitoring of reactor vessel level instrumentation system	Allowable weld load used was one-third above the American Institute of Steel Construction (AISC) allowable value.	Calculations were revised to use the AISC allowable value. Results were shown to be acceptable.	Qualified
NSSS-2	Three-bay 7300 process protection system cabinet	3Z121ZRR014	Electronics in cabinet to process safety-grade signals for plant protection	(1) Cabinet tested was different model number than the one in plant. (2) Printed circuit cards were not bolted into place.	(1) Drawings showed link between the two model numbers. (2) The applicant showed documentation of these bolts and also that the status of the cabinet was being tracked.	Qualified
NSSS-3	Operator interface module	C1EW-PK-6874	Controls the essential cooling water flow to the essential chiller condensor	The model numbers of actual interface modules were inside a housing and could not be checked in the field.	Traceability of model number was shown in drawings. Link between equipment tested and equipment installed was established.	Qualified
NSSS-4	8-in. special check valve	2M101X-CS-0004	Containment isolation, containment heat removal, and radioactive fission product scrubbing			Qualified

*NSSS = nuclear steam supply system; BOP = balance of plant.

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Table 3.1 (Continued)

Number*	Equipment	Applicant ID number	Safety function	Findings	Resolution	Status
NSSS-6	Fast-response well-type resistance temperature detector (RTD)	AIRC-TE-0410X	Reactor coolant loop temperatures, overtemperature trip signal, and overpower trip signal	There was a discrepancy in tag numbers between SQRT list and field.	AIRC-TE-0410X is the tag number for the RTD which is not installed. AIRC-TB-0410X is the tag number for the junction box into which the RTD terminates.	Qualified
NSSS-7	Main steam isolation valve (MSIV) solenoid valve	AIMS-FSY-7444 (valve), AIMS-FY-7414A, B & C	Vents when deenergized to permit MSIV to be in its safety position	Lock nut for the adjusting screw on the speed control solenoid was missing.	The work is being tracked by document SWR08295, MCL #49014. Program is satisfactory. Issue is resolved.	Qualified
NSSS-8S	Spent fuel pool cooling pump	2R211NPA101A	Removes decay heat	Constant level oiler was loose and not in proper position. It was also leaking.	The problem was put on the Squawk list, which is controlled by document DG-002. This ensures it will be fixed when the program is completed. Issue is resolved.	Qualified
NSSS-9	Control rod drive mechanism (CRDM)	1R151NRD101A	Maintains integrity of reactor coolant system pressure boundary and inserts control rods when desired	(1) Common support motion was used at different elevations in dynamic analysis. (2) Purchase order does not have specification.	(1) Support points were demonstrated to be linked with respect to CRDM. (2) Purchase order change notice was produced which had specification.	Qualified
NSSS-10	Radioactive waste cleanup isolation valve	A1SI-FV-3936	Isolates radioactive waste from the refueling water purification system after an accident			Qualified

*NSSS = nuclear steam supply system; BOP = balance of plant.

Table 3.1 (Continued)

Number*	Equipment	Applicant ID number	Safety function	Findings	Resolution	Status
NSSS-11	High head safety injection pump	2N121NPA101C	Supplies water for emergency core cooling following a loss-of-coolant accident (LOCA) or a steamline break accident	Response spectrum analysis to show end deflections and stresses during a seismic event was too complex to be reviewed at audit.	Westinghouse will provide auditable summary of report.	To be qualified
NSSS-12	Residual heat removal pump	2R161NPA101A	Small-break LOCA recovery (long-term cooling)	Seal water coolant was leaking.	Result of in-process work is governed by document SWR 10168. Also tracked by NCL #078420.	Qualified
NSSS-13	Refueling water purification pump	9RZ11NPA103A	Passive pump. Maintains pressure boundary	Surprise item. Field observation and brief documentation review to check for completeness were performed.		Acceptable
NSSS-14	Thermocouple reference junction box	4Z13[illegible]ETB0002	Monitors core exit temperature for reactor vessel level instrumentation and core subcooling	(1) Identification tag was missing. (2) The junction box was open when it is supposed to be maintained pressure tight.	(1) Being tracked by NCL #82450. (2) Being tracked by NCL #79108. Issue is [illegible].	Qualified
BOP-1	Isolation/ termination cabinet	4Z551ZLP660A-02	Provides Class 1E to non-Class 1E digital and analog signal conversion	(1) Incompatibility existed between functional requirements and qualification temperature. (104°F vs 90°F). (2) Qualification is based on the cabinet's being rigid. However, this is not demonstrated.	(1) Reconciled and corrected. (2) To be resolved. Evidence should be provided to verify rigidity.	To be qualified

*NSSS = nuclear steam supply system; BOP = balance of plant.

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Table 3.1 (continued)

Number*	Equipment	Applicant ID number	Safety function	Findings	Resolution	Status
BOP-2	24-in. butterfly valve--motor operated	3X201T-CC-0052	Provides component cooling water individual train isolation from common header	Qualification report describes anomaly not on SQRT form. Also, anomaly is not addressed.	Inadvertent omission. Generic test and South Texas requirements were satisfied before level at which anomaly occurred. Issue is resolved.	Qualified
BOP-3	Centrifugal water chiller	3V111VCH003	Provides chilled water to safety class air handling unit			
BOP-4	Isolation relay	3E251ERR136	(1) Provides means of supplying water to steam generator (2) Provides emergency core cooling following a LOCA			Qualified
BOP-5	Safety class air handling unit	3V121VAH012	Maintains cubicle design temperature			Qualified
BOP-6	Steam generator main steam safety valve	N1MS-PSV-7430B	Provides overpressure protection for the steam generator			Qualified
BOP-7	Single module termination cabinet	3E121ETCA04	Provides and maintains electrical connection between field devices and control room	Stresses in cable support elements in the finite element model were 4% to 6% above allowable values.	Some conservatism was included in the response spectra used in the analysis. Also cable support elements could not be modeled exactly since cabinet sheet metal was not included	Qualified

*NSSS = nuclear steam supply system; BOP = balance of plant.

Table 3.1 (continued)

Number*	Equipment	Applicant ID number	Safety function	Findings	Resolution	Status
BOP-7 (cont'd)					in model. This adds more conservatism. It is judged to be satisfactory. Issue is resolved.	
BOP-8	Reactor coolant hot leg sample isolation valve	B1PS-FV-4456	Provides containment isolation	(1) Post-seismic check found screws that had loosened during testing. (2) Valve was not included in maintenance book. (3) Nozzle loads in plant exceed those used in testing.	(1) Valve has been modified to preclude screw loosening. Issue is resolved. (2) Valve should be included in maintenance book. (3) A generic program to reconcile loads on pumps and valves is in progress. Completion of the program should be confirmed.	To be confirmed
BOP-10	Reactor makeup water pump	3R271MPA101A	Provides seismic Category I source of makeup water to component cooling water storage tank and spent fuel pool cooling system			Qualified

*NSSS = nuclear steam supply system; BOP = balance of plant.

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Table 3.1 (Continued)

Number[a]	Equipment	Applicant ID number	Safety function	Findings	Resolution	Status
BOP-11	Instrument control room panel	5Z3412CP003	Monitors and controls standby diesel generator	(1) There was no permanent tag. (2) The qualification of Class 1E devices is not complete. (3) Qualified life of the limited life components has not been established.	(1) Being tracked by MCL #082781. (2) In progress. (3) In progress.	To be confirmed
BOP-12	Class 1E terminal blocks	1600MUCJ86425	Maintains circuit continuity	Tag number was missing.	Individual terminal blocks are not given tag numbers. Number shown is fictitious number used to track qualification status. Issue is resolved.	Qualified
BOP-13	4-in.-900# Mark I globe	A1SB-FV-4150	Isolates break or other source of water loss to prevent steam generator water loss	Surprise item. This was checked to ensure retrievability and completeness of the package.		Acceptable

[a]NSSS = nuclear steam supply system; BOP = balance of plant.

Table 3.2 Summary of PVORT audit for South Texas Unit 1

Equipment description	Plant ID no.	Function	Findings	Resolution	Status
Chemical and volume flow control valve (Grinnel 2-in. diaphragm valve)	B1CV-FV-8400B (NSSS)	Normally open. Closes on a boric acid storage tank lo-lo level.	--	--	Closed
Chemical and volume control isolation valve (Westinghouse 6-in. gate valve)	2R171X-CV-0112C (NSSS)	Normally closed. Opens on a safety injection signal or volume control tank lo-lo level signal to provide flow to charging pump suction.	--	--	Open[1]
Boric acid transfer pump (Crane Chempump, 125 gpm)	3R171NPA103A (NSSS)	Normally operates to provide boric acid for chemical and volume control system makeup and boric acid purification. Emergency function is to provide flow to the charging pump suction for emergency boration.	[2], [3]	[4]	Open[5]
Auxiliary feedwater pump (Bingham Willamette Co., 600 gpm)	3S141MPA04 (BOP)	Normally in standby. Operates on an engineered safety feature (ESF) signal or manually to provide emergency feedwater to the steam generators.	[6]	[4]	Open[5]

See footnotes at end of table.

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Table 3.2 (Continued)

Equipment description	Plant ID no.	Function	Findings	Resolution	Status
Auxiliary feedwater minimum flow recirculation valve (Yarway 4-in. auto recirculation valve)	3S141T-AF-0091 (BOP)	Normally lined up for recirculation with its associated auxiliary feedwater pump in standby. Aligns itself to flow to steam generator or recirculates to storage tank as required on an ESF signal.	7	4	Open[5]
Component cooling surge tank isolation valve (Rockwell 24-in. butterfly valve)	3R101T-CC-0132 (BOP)	Normally open to allow flow from surge tank. Closes to isolate surge tank on a low surge tank level.	--	--	Closed
Essential cooling water pump (Hayward Tyler, 20,610 gpm)	3R281NPA101B (BOP)	Normally provides flow from essential cooling pond to serviced components. In an emergency (safety injection signal, loss of offsite power, or low water header pressure) provides cooling water to essential equipment.	--	--	Closed
Feedwater isolation valve (WKM 18-in. gate valve)	A1FW-FV-7141 (BOP)	Normally open. Closes on a feedwater isolation signal.	--	--	Closed

See footnotes at end of table.

Table 3.2 (Continued)

Equipment description	Plant ID no.	Function	Findings	Resolution	Status
Auxiliary feedwater stop-check valve (Rockwell 4-in. stop-check valve)	2S141T-AF-0019 (BOP)	Normally closed. Opens on an ESF signal and auxiliary feedwater pump #14 operation to feed steam generator 1D.	--	--	Closed
Chilled water isolation valve (Valtek 4-in. butterfly valve)	C1H-TV-9497A (BOP)	Normally open acting as a temperature regulating valve for the electrical auxiliary building. Opens completely on a safety injection signal.	--	--	Closed
Reactor water makeup isolation valve (WKM 4-in. globe valve)	B1RM-FV-7663 (BOP)	Normally open. Closes on a safety injection signal to isolate nonessential service water.	--	--	Closed
Main steam isolation valve (Atwood & Morrill 30-in. globe valve)	AIMS-FSV-7414 (BOP)	Normally open. Closes on an isolation signal.	--	--	Closed
All pumps and valves important to safety	--	Operate as required during the life of the plant under accident conditions.	8-12	4	Open[5]

See footnotes on next page.

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Table 3.2 (Continued)

[1]Qualification status will be closed when environmental qualification radiation concerns have been resolved (see SER Section 3.11).

[2](Specific issue) During the document review, the component appeared to be qualified to three different radiation levels. The applicant shall (1) modify the WCAP-8687 and PVORT form to correct the apparent discrepancy and (2) confirm that the equipment qualification file has been supplemented with the appropriate documentation.

[3](Specific issue) During the documentation review, documentation supporting operation at degraded voltages could not be provided. The applicant shall (1) provide a copy of the test report that references operability of canned motors at reduced voltages, (2) describe the basis for similarity of the test results, and (3) confirm that the equipment qualification file has been supplemented with the appropriate information.

[4]At the conclusion of the site audit, the staff summarized the open issues. The applicant was informed of the appropriate actions necessary to resolve the specific and generic issues before fuel load.

[5]Qualification status will be closed when specific and generic issues have been resolved.

[6](Specific issue) At the time of the audit, the applicant had not tested the new design to minimize the impact of moisture in the auxiliary feedwater turbine driving steam. The applicant shall confirm when preoperational testing is satisfactorily completed, identify deficiencies discovered during testing, and describe the disposition of the deficiencies.

[7](Specific issue) During the audit, the applicant could not provide a preventive maintenance schedule because it had not been developed. The applicant shall provide a copy of the maintenance schedule demonstrating that the manufacturer's recommended maintenance will be performed.

[8](Generic issue) At the conclusion of the PVORT audit, it was apparent that a complete list of active pumps and valves had not been provided in the FSAR. At the site audit, the applicant committed to confirm that all active NSSS and BOP pumps and valves are correctly identified in the FSAR.

[9](Generic issue) Some preservice tests required to be completed before fuel load have not yet bee performed. At the site audit, the applicant committed to confirm that all appropriate preservice tests have been completed before fuel load.

[10](Generic issue) Some pumps and valves important to safety have not been completely qualified and installed. At the site audit, the applicant committed to confirm that all pumps and valves important to safety are completely qualified and installed before fuel load. Also, the applicant shall confirm that the original loads used in tests and analyses to qualify pumps and valves important to safety are not exceeded by any new loads (i.e., design load reconciliation).

[11](Generic issue) The applicant shall perform a review to ensure that nonconformances issued for safety-related pumps and valves during the transition of architect-engineers from Brown and Root to Bechtel were properly picked up by a Bechtel program and dispositioned.

[12](Generic issue) The 30-day postaccident operating time for qualifying equipment is not consistent with postaccident times used at other plants. Typically, postaccident periods of 100 days or more are used. The applicant shall provide information that demonstrates how a 100-day minimum postaccident operability time is met.

NOTE: NSSS = nuclear steam supply system; BOP = balance of plant.

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5 REACTOR COOLANT SYSTEM

5.2 Integrity of Reactor Coolant Pressure Boundary

5.2.4 Reactor Coolant Pressure Boundary Inspection and Testing

See Section 6.6.3, "Evaluation of Compliance With 10 CFR 50.55a(g) for South Texas Unit 1."

5.4 Component and Subsystem Design

5.4.2 Steam Generators

5.4.2.2 Steam Generator Tube Inservice Inspection

This section was prepared with the technical assistance of DOE contractors from the Idaho National Engineering Laboratory.

5.4.2.2.2 Evaluation of the Inspection Program

This evaluation supplements conclusions in this section of the SER, which addressed the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g). In the SER, the staff reported that it considered the PSI examination of the steam generator tubing at South Texas Unit 1 a confirmatory issue, contingent on the applicant conforming with the requirements of the applicable Standard Technical Specification.

Since SSER 2 was issued, the staff has reviewed a submittal dated January 5, 1987 containing the "Preservice Inspection Summary Report of Steam Generator Tubing at the South Texas Project Electric Generating Station--Unit 1." This document described the eddy current examination performed by Babcock and Wilcox (B&W) and subsequently by Westinghouse Electric Corporation. B&W performed the initial eddy current examination in the scope of PSI; however, on the basis of these results, operations were performed in several tubes to remove restrictions to the passage of the eddy current probes. These operations rendered the B&W PSI data unacceptable as a baseline for future inservice inspection; therefore, Westinghouse reexamined the affected areas of the reworked tubes.

PSI examinations were performed on the full length (from tube end to tube end) of each tube that had not been previously removed from service in all four steam generators.

On the basis of the review of the above document, the staff has concluded that the PSI Program Plan for steam generator tubing at South Texas Unit 1 is acceptable and complies with 10 CFR 50.55a(g)(3). Therefore, Confirmatory Item 10 is closed.

5.4.7 Residual Heat Removal System

In the SER, the staff noted that Branch Technical Position (BTP) RSB 5-1 (NUREG-0800) requires natural circulation tests with supporting analyses to confirm

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that (1) adequate mixing of borated water added before or during cooldown can be achieved under natural circulation conditions and the times required to achieve such mixing can be estimated and (2) the cooldown under natural circulation conditions can be achieved within the limits specified in the emergency operating procedures. Comparison with the performance of previously tested plants of similar design may be substituted for these tests.

The applicant had indicated that the natural circulation test results at the Diablo Canyon Nuclear Power Plant would be applicable and, in response to a staff inquiry, had provided information that indicated hydraulic similarity between the two plants. The applicant committed to review the Diablo Canyon test results in order to demonstrate their applicability to South Texas (SER Confirmatory Item 11).

A safety evaluation report (Schierling, March 3, 1987) contains the NRC evaluation of the Diablo Canyon natural circulation tests, which was based on a Brookhaven National Laboratory (BNL) study. The staff concluded that the basic objectives of the test were met. This included demonstration that natural circulation was established, adequate boron mixing was achieved, and reactor coolant system (RCS) cooldown and depressurization to residual heat removal (RHR) entry conditions was achieved within a reasonable time. There was, however, a question with regard to upper head cooling. During the test the control rod drive mechanism (CRDM) fans were operated almost continuously to maintain the CRDM temperature within acceptable limits, and operation of these fans effected adequate subcooling of the reactor vessel upper head (RVUH) water volume. However, the CRDM fans are not seismic Category I. The BNL analyses conservatively estimated a lengthy "soak time" for the upper head (UH) before depressurization to RHR entry conditions could be established without void formation if the CRDM fans were not used. This was based on a conservative premise that there would be little or no mixing between UH liquid layers and that the only heat transfer mechanism was through metal conduction. Since the South Texas RVUH volume is considerably larger than that of Diablo Canyon and the South Texas auxiliary feedwater (AFW) supply is limited, the staff requested that the applicant address this concern.

In a letter dated February 13, 1987, the applicant stated that additional calculations were performed to show that the South Texas UH fluid could be cooled down and depressurized to RHR entry conditions without voiding in the UH by using the safety-grade reactor vessel head vent system to maintain UH subcooling and enhance mixing. No credit was taken for operation of the CRDM fans. The UH thermocouples would be used to provide a reliable and redundant indication of UH subcooling. In a letter dated February 23, 1987, the applicant provided additional information with regard to hydraulic similarity between South Texas and Diablo Canyon. Because of the higher decay heat of the South Texas reactor, a natural circulation South Texas flow/Diablo Canyon flow of 1.02 was calculated. The South Texas applicant estimates the maximum AFW requirements as 377,000 gallons. The auxiliary feed tank's minimum useable capacity is 445,000 gallons.

In response to a staff inquiry, the applicant provided additional information on the head vent system in a letter dated March 30, 1987. The head vent system is designed for a total of 26 valve open/close cycles. A total of six cycles were calculated for a safety-grade cooldown event. The applicant committed to reevaluate the head vent system after each plant operating event during which

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the system is utilized in accordance with ASME Code Section III level D faulted condition requirements. This evaluation will consist of determining the allowable deformations (deflections and rotations) of the system under level D loads and comparing them with the actual (observed) deformations, if any, in the system. The head vent hydraulic flow characteristics were verified and found adequate for this application. Additionally, the CRDM vent fans, although not designed to seismic Category I, are powered by Class 1E buses. It is therefore likely that the fans would be utilized for UH cooling during a loss-of-offsite-power (LOOP) event except for an earthquake-caused LOOP.

The staff concludes that the applicant has adequately demonstrated the applicability of the Diablo Canyon tests to South Texas with regard to RCS natural circulation and boron-mixing capabilities and has further shown that the South Texas design will enable RCS cooldown and depressurization to RHR entry conditions within a reasonable period of time under natural circulation conditions, using only safety-grade equipment and safety-grade secondary water supply. The staff, therefore, concludes that the applicant has met the test requirements of BTP RSB 5-1, and Confirmatory Item 11 is closed.

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6 ENGINEERING SAFETY FEATURES

6.2 Containment Systems

6.2.6 Containment Leakage Testing

Containment Airlock Surveillance

By letter dated January 15, 1986, the applicant requested an exemption from certain requirements of Appendix J to 10 CFR 50.

Paragraph III.D.2(b)(ii) of Appendix J states: "Air locks opened during periods when containment integrity is not required by the plant's Technical Specifications shall be tested at the end of such periods at not less than P_a."

Whenever the plant is in cold shutdown (mode 5) or refueling (mode 6), containment integrity is not required. However, if an airlock is opened during modes 5 and 6, Paragraph III.D.2(b)(ii) of Appendix J requires that an overall airlock leakage test at not less than P_a be conducted before plant heatup and startup (i.e., entering mode 4). The existing airlock doors are so designed that a full-pressure (i.e., P_a (37.5 psig)) test of an entire airlock can only be performed after strong backs (structural bracing) have been installed on the inner door. Strong backs are needed because the pressure exerted on the inner door during the test is in a direction opposite to that of the accident pressure direction. Installing strong backs, performing the test, and removing the strong backs require several hours, during which access through the airlock is prohibited.

When no maintenance has been performed on the airlock that could affect its sealing capability, the airlock doors have been closed in accordance with the applicant's procedure, and the periodic 6-month test at P_a required by Paragraph III.D.2(b)(i) of Appendix J has been performed on schedule, there is no reason to expect the airlock to leak excessively just because it has been opened in a shutdown or refueling mode. Performing the door seal leak test of Paragraph III.D.2(b)(iii) of Appendix J is sufficient, in this case, to demonstrate the continuing integrity of the airlock.

Accordingly, the staff concludes that the applicant's proposed approach of substituting the seal leakage test of Paragraph III.D.2(b)(iii) for the full-pressure test of Paragraph III.D.2(b)(ii) of Appendix J is acceptable when no maintenance that could affect sealing capability has been performed on an airlock. Whenever maintenance that could affect sealing capability has been performed on an airlock, the requirements of Paragraph III.D.2(b)(ii) of Appendix J must still be met by the applicant.

The special circumstances for granting this exemption pursuant to 10 CFR 50.12 have also been identified. The purpose of Appendix J to 10 CFR 50 is to ensure that containment leaktight integrity can be verified periodically throughout

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service lifetime so as to maintain containment leakage within the limits specified in the facility Technical Specifications. The proposed alternative test method is sufficient to achieve this underlying purpose in that it provides adequate assurance of continued leaktight integrity of the airlock. In addition, at the time this section of Appendix J was revised in 1980, the staff did not contemplate the undue hardship and cost that would result from the requirement to perform a time-consuming full-pressure test before starting up from even the shortest cold shutdown during which the airlock had been used for containment entry. Because of this, the staff has already granted this same exemption to numerous plants and intends to revise Appendix J to alleviate the need for further similar exemptions. Consequently, the special circumstances described by 10 CFR 50.12(a)(2)(ii) and (iii) exist in that application of the regulation in these particular circumstances is not necessary to achieve the underlying purpose of the rule in that the applicant has proposed an acceptable alternative test method that accomplishes the intent of the regulation. Compliance would result in undue hardship that would be significantly in excess of that contemplated when the regulation was adopted in that plant startup would be delayed while an overall airlock leakage test was performed at full pressure. The effort and delay required are not warranted by the resulting safety benefit.

Therefore, a partial exemption from this requirement (10 CFR 50, Appendix J, Paragraph III.D.2(b)(ii)) is justified and acceptable, and the applicant's proposal to adopt Surveillance Requirement 4.6.1.3 of Revision 4 of NUREG-0452, "Standard Technical Specifications for Westinghouse Pressurized Water Reactors," is acceptable (NUREG-0452, Rev. 4, was written to accommodate this type of exemption). Further, the staff finds that, in accordance with 10 CFR 50.12(a)(1), the requested partial exemption is authorized by law, will not present an undue risk to the public health and safety, and is consistent with the common defense and security, and that, in accordance with 10 CFR 50.12(a)(2)(ii) and (iii), special circumstances, as discussed above, are present.

6.3 Emergency Core Cooling System

6.3.5 Performance Evaluation

6.3.5.1 Large-Break LOCA

See Section 15.6.5.1.1.

6.3.5.2 Small-Break LOCA

See Section 15.6.5.1.2.

6.6 Inservice Inspection of Class 2 and 3 Components

This section was prepared with the technical assistance of DOE contractors from the Idaho National Engineering Laboratory.

6.6.3 Evaluation of Compliance With 10 CFR 50.55a(g) for South Texas Unit 1

This evaluation supplements conclusions in this section of the SER, which addressed the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g). In the SER, the staff reported that, on the basis of its review of the "Examination Plan for the PSI Examination of Selected

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Components and Piping of the STP Unit 1," it considered the review of the preservice inspection (PSI) program for the Class 2 and Class 3 components an open issue subject to the applicant

(1) addressing the concept used to select component supports subject to PSI

(2) docketing a commitment to perform a volumetric examination on an acceptable sample of the Class 2 welds in the chemical and volume control system

(3) submitting all relief requests with a supporting technical justification

Since the SSER 2 was issued, the staff has completed its review of the following information:

(1) the FSAR through Amendment 56 dated November 1986

(2) a January 9, 1986 submittal from the applicant containing revised responses to NRC Questions 250.01N and 250.07N

(3) A June 9, 1986 submittal from the applicant containing comments on the SER

(4) an August 28, 1986 submittal from the applicant containing a request for relief from ASME Code Section XI PSI examination requirements for pipe welds and supports in open-ended portions of the containment spray system

(5) "Preservice Inspection Examination of Component Supports of South Texas Project Electric Generating Station--Unit 1," submitted August 28, 1986

(6) requests for relief from the ASME Code Section XI requirements that the applicant has determined are impracticable for South Texas Unit 1, submitted December 9, 1986

On the basis of the construction permit issuance date of December 22, 1975, 10 CFR 50.55a(g)(3) requires that the PSI program be developed and implemented using at least the edition and addenda of Section XI of the ASME Code applied to the construction of the particular components.

The use of later referenced Code editions is acceptable as specified by 10 CFR 50.55a(g)(3). The applicant has prepared a program based on the requirements of the ASME Code Section XI, 1980 Edition with Addenda through Winter 1981 (80W81), except for Class 2 piping welds in the residual heat removal, emergency core cooling, and containment heat removal systems. For these systems, the extent of examination is that specified by the 1974 Edition with Addenda through Summer 1975 (74S75) as required by 10 CFR 50.55a(b)(2).

Staff review of the applicant's revised response to NRC Question 250.01N, submitted January 9, 1986, and "Preservice Inspection Examination of Component Supports of South Texas Project Electric Generating Station--Unit 1," submitted August 18, 1986, shows the following:

(1) Component supports for Class 1, 2, and 3 components are being examined and tested during the PSI in accordance with 80W81 ASME CODE Section XI, Subsection IWF.

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(2) Visual examinations (VT-3 and VT-4) are being performed on the supports of nonexempt components in accordance with IWF-2510(a) and (b).

(3) Preservice testing of snubbers as required by IWF-5000 was conducted in the snubber manufacturer's shop.

(4) Augmented preservice examination and preoperational testing requirements for snubbers, as specified in the October 17, 1980 letter to the applicant for the detection of inoperable and incorrectly installed snubbers, have been implemented.

(5) The augmented examinations and tests are being performed in conjunction with either the PSI of component supports or during the preoperational test program.

In its June 9, 1986 submittal of "Comments on the Safety Evaluation Report (SER), NUREG-0781," the applicant reported that the chemical and volume control system (CVCS) was not included in the augmented volumetric sample program because this system does not serve an emergency core cooling system (ECCS) function. The charging pumps at South Texas are not used for the safety-injection function of the ECCS. At South Texas, separate high head and low head safety injection pumps perform the ECCS function. On this basis, the staff concludes that if the CVCS does not serve an ECCS function, an augmented volumetric examination would not be required.

Requests for relief from the ASME Code Section XI requirements which the applicant has determined are impracticable for Class 2 and Class 3 systems and components were received in submittals dated August 28 and December 9, 1986. All of the relief requests were supported by information pursuant to 10 CFR 50.55a(a)(3). Therefore, the staff evaluated the ASME Code-required examinations that the applicant had determined were impracticable and concluded that the applicant has demonstrated that either (1) the proposed alternatives would provide an acceptable level of quality and safety or (2) compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

On the basis of its review of the applicant's submittals and the granting of relief from these preservice examination requirements, the staff concludes that the PSI program for the Class 2 and Class 3 components at South Texas Unit 1 is acceptable and complies with 10 CFR 50.55a(g)(2). The detailed evaluation supporting this conclusion is provided in Appendix V to this report.

The initial inservice inspection program plan has not been submitted by the applicant. The staff requires that this plan be submitted with 6 months from the date of issuance of the operating license. The evaluation of this plan will be based on 10 CFR 50.55a(g)(4), which requires that the initial 120-month inspection interval shall comply with the requirements in the latest edition and addenda of the Code incorporated by reference in 10 CFR 50.55a(b) on the date 12 months before the date of issuance of the operating license. This plan will be evaluated after the applicable ASME Code edition and addenda can be determined and before the first refueling outage when inservice inspection begins.

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7 INSTRUMENTATION AND CONTROLS

7.3 Engineered Safety Features System

7.3.2 Specific Findings

7.3.2.2 Safety Injection Signal To Close Main Steam Isolation Valves

In the SER, the staff stated that the South Texas Project had a unique design related to main steam isolation logic. The main steam isolation valves (MSIVs) were automatically closed by the safety injection (SI) signal. The staff had a concern that spurious actuation of the SI signal would result in more frequent MSIV closures. potentially resulting in more safety valves lifting and possibly sticking, overpressurization of the steam generator tubes, etc. Most other Westinghouse plants use the containment high-2 signal to close MSIVs. The applicant was requested to justify that the South Texas design will not significantly challenge the safe shutdown capability. The applicant had provided documentation that indicated the design would be changed. As stated in the SER, this was a confirmatory item pending staff review of the final design.

By letter dated October 20, 1986, the applicant provided annotated FSAR revisions including drawings that depicted the new MSIV closure logic. As currently designed, the MSIV will be closed by manual actuation or by one of the following signals: (1) high-2 containment pressure signal, (2) high steam pressure negative rate, (3) low-low compensated T_{cold}, or (4) low compensated steamline pressure. The staff has reviewed the applicable drawings (e.g., 8758022 sheets 8 and 9) and verified that the MSIV closure logic has been modified in that the SI actuation logic has been deleted and that the actuation signals noted above are correct. Therefore, the staff considers Confirmatory Item 17 resolved.

7.3.2.5 Isolators Test Report

Chapter 7 of the FSAR states that control signals that are derived from protection systems are isolated from the protection channels by isolation amplifiers. The paragraph detailing the isolation amplifiers also describes faults that could originate in the control channel and states that the purpose of the isolator is to prevent these postulated faults from affecting the protection channel.

The staff reviewed the FSAR and discussed the isolation devices with the applicant. It was noted by both the staff and the applicant that the isolation devices for the qualified display processing system (QDPS) would be reviewed as a separate issue as stated in Section 7.5.2.9 of the SER. In a letter dated June 17, 1985, the applicant stated that qualification tests were being performed on the following four types of isolators:

(1) digital (optical) isolators for the emergency response facility data acquisition and display system (ERFDADS) computer inputs

(2) analog (transformer coupled) isolators for the ERFDADS inputs

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(3) digital (optical) isolators for the radiation monitoring system

(4) digital isolators for the diesel generator control panels

The commitment to provide these test results to the staff was documented as an open item in SER Section 7.1.4.1.

As stated in the SER, it is the staff's position that the above devices be qualified isolators for interfacing between safety-related and non-safety-related systems. As part of the open item, the applicant was to provide the following information for staff review and approval before an operating license is granted:

(1) For each type of device used to accomplish electrical isolation at South Texas, describe the specific testing performed to demonstrate that the device is acceptable for its application(s). This information should include elementary diagrams where necessary to indicate the test configuration and the means by which the maximum credible faults were applied to the devices.

(2) Provide data to verify that the maximum credible faults applied during the test were the maximum voltage/current to which the device could be exposed, and define how the maximum voltage/current was determined.

(3) Provide data to verify that the maximum credible fault was applied to the output of the device in the transverse mode (between signal and return) and other faults were considered (i.e., open and short circuits).

(4) Define the pass/fail acceptance criteria for each type of device.

(5) Provide information to verify that the isolation devices comply with the environmental qualifications (10 CFR 50.49) and the seismic qualifications that are the basis for plant licensing.

The applicant responded to the open item in a letter dated October 31, 1986, which included a summary of the isolator test reports. The staff reviewed the submittal and sent a request for additional information (RAI) to the applicant on January 13, 1987. The applicant responded to the RAI in a letter dated February 19, 1987.

The discussion that follows addresses the applicant's submittals regarding these isolators and evaluates the isolators' ability to meet GDC 24 and Institute of Electrical and Electronics Engineers (IEEE) Standard 279-1971 requirements for isolation.

The review criteria for the isolator test reports state that the transmission of signals from Class 1E systems (i.e., protection systems) shall be through isolation devices and that these isolation devices shall be made a part of the Class 1E system. The criteria further state that no credible failure at the output (the non-Class 1E side) of the isolators shall jeopardize the integrity of the Class 1E input to the isolator.

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The response to the open item indicated that the following isolators were used at South Texas Units 1 and 2:

(1) Energy Incorporated (EI)--Analog Model No. 00798-XX, transformer-type isolation barrier and Digital Model No. 01026-17, optical-type isolation barrier--used in the ERFDADS

(2) General Atomic Company (GA)--communication isolation devices 0357-5200, IAC-24 and IDC-24, all optical-type isolation barriers--used in the RM80 digital radiation monitoring system

(3) Cooper Energy System (CES)--digital isolators composed of solid-state transmitters, receivers linked by fiberoptic cables--used in the diesel generator control panels

All three suppliers subjected their isolators to functional and hipot tests and to a surge withstand capability test. In addition, the isolators were qualified according to IEEE Standard 323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations," and IEEE Standard 344-1975, "IEEE Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations." The isolators are located in a mild environment; therefore, 10 CFR 50.49, which addresses harsh environments, does not apply.

The pass/fail criteria for the above testing are that there shall be no evidence of insulation breakdown or flashover, that the device shall maintain all isolation barrier characteristics, and that the device shall pass pre- and post-functional tests. Each type of isolator provided by the three suppliers passed the pass/fail criteria. This satisfies the requirement that the isolators be made a part of the Class 1E system with which they are associated.

In addition to the testing previously described, the EI and GA isolators were subjected to a maximum credible fault (MCF) test applied to the plus and minus output terminals of the isolators in the transverse mode. The MCF voltage/current values to which the isolators could be exposed were 140 V ac at a potential current of 20 amps for the EI devices and 140 V dc at a potential of 35 amps for the GA devices.

For the EI devices, the MCF pass/fail criteria state that the devices shall maintain the isolation barrier before, during, and after application of the MCF. For the GA devices, which are used in the RM80 system (radiation monitoring), the MCF pass/fail criteria state that the signals transmitted within the system shall remain unchanged during and after the application of the MCF.

On the application of the MCF to the non-Class 1E output of the EI analog and digital isolation devices, the test instrumentation monitoring the Class 1E input circuits did not detect any discernible voltages on the input, indicating that the isolation barrier had not been breached and the isolator had successfully withstood the challenge of the MCF. Similarly, when MCF was applied to the output terminals of the RM80 system's isolators, no change in the RM80 system signals was detected by the test instrumentation monitoring the signal.

The CES isolators use a fiberoptic cable to interface the Class 1E signals with the non-Class 1E systems. Because fiberoptic cables have properties that qualify

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them as ideal isolators, specific MCF tests are not necessary. These properties are as follows:

(1) Fiberoptic cables are totally dielectric; therefore, the electrical fault voltage/current cannot propagate from one end of the cable to the other end.

(2) Fiberoptic cables are not susceptible to electrical interference; therefore, the electrical noise, such as electrostatic coupling, common mode, or crosstalk, cannot be induced into or propagate through the cable.

All of the isolators passed the pass/fail criteria for the MCF tests. Therefore, the requirement that the isolators protect the Class 1E side of the isolator is satisfied.

In addition to the isolator test reports, the applicant supplied data showing that the safety systems had been protected from any electrical interference that might be generated as a result of using fiberoptic cables, shielded cables, and metallic shielding and by physical separation of equipment. The applicant also stated that the Class 1E side of the isolators is powered by a Class 1E power source, while the non-Class 1E side of the isolators is powered by a non-Class 1E power source.

On the basis of its review of the applicant's submittals with respect to isolation devices, the staff concludes that these electrical isolation devices may be used for interfacing between Class 1E systems and non-Class 1E systems. It also concludes that these isolation devices meet GDC 24 and IEEE Standard 279-1971. Therefore, the staff concludes that the open item regarding the acceptability of isolation between safety-related and non-safety-related systems is resolved. As stated previously, the isolation devices utilized within the QDPS are being reviewed separately and will be discussed in Section 7.5.2.9 of a future supplement.

7.5 Information Systems Important to Safety

7.5.2 Specific Findings

7.5.2.5 Qualified Display Processing System Software Verification and Validation Program

The applicant has installed a microprocessor-based system to perform several safety-related functions at South Texas. The microprocessor-based system is called the qualified display processing system (QDPS). The system performs the following functions:

(1) data acquisition, processing, and qualified display for postaccident monitoring

(2) data acquisition, display, and analog control for safe shutdown to address separation/isolation concerns for a postulated control room/relay fire

(3) data acquisition and digital processing of steam generator water level signals and primary coolant system hot-leg temperature signals for

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transmission to the reactor trip system/engineered safety features actuation system and for qualified display

The staff performed a comprehensive review of the verification and validation (V&V) program on the QDPS to ensure the functionality of the system to a level commensurate with that described in the system requirements.

Four staff audits were conducted on the QDPS design and V&V process. The first audit was held in August 1985, and the primary areas of discussions were the QDPS V&V plan and the verification process (letter to applicant dated January 30, 1986). The second audit was held in March 1986, and the primary area of discussion was the QDPS design and design process (letter to applicant dated May 19, 1986). The third audit was conducted in July 1986, and the primary area of discussion was the validation plan and process (letter to applicant dated October 7, 1986). The final audit was held in November 1986, and the primary area of discussion was the review of the implementation of the validation plan (letter to applicant dated January 29, 1987).

Several open issues were raised during the four audits conducted by the NRC staff. Before the conclusion of the final audit, all open issues with four exceptions (Issues 7, 8, 9, and 10) were resolved to the satisfaction of the staff. These remaining open issues were resolved with the issuance of the QDPS final V&V report and its supplement. The open issues and their respective resolutions are given below.

Issue 1--No Evidence of the Use of a Requirements Matrix To Structure the Decomposition of the Functional Requirements

Decomposition From Functional Requirements to Software Design Specification May Be Incomplete

Examination of the documents from the second audit indicated that the functional requirements from the applicant were not well documented and were the result of dynamic evolution. Before the second audit there was an accumulation of the documentation for the functional requirements in the appropriate form with the appropriate levels of signatures, the documentation of the software design documents, and a functional requirements matrix prepared by the design group showing an audit trail from the functional requirements to the corresponding software unit. However, the completeness of this matrix could not be demonstrated to the satisfaction of the second audit team. The abbreviated format of the matrix was judged to indicate incompleteness by restricting the entries to software functional requirements and by not including those which were addressed by hardware or by other subsystems.

Before the third audit a second functional requirements matrix was prepared by two engineers who were independent of the design team. For each subsystem every requirement was listed by document number and a paragraph number with a full description of the requirement, a statement of where the requirement was met, and the functional test required for validation. The third audit team reviewed this matrix and its associated documentation and found it acceptable. However, the completed validation phase was accepted at the fourth audit.

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At the fourth audit, the staff evaluated the status of the verification and validation testing. The verification and validation testing of the base-scope was complete as well as the verification and validation testing of the control/steam generator water level compensation system (SGWLCS) upgrades. The verification and validation of the upgrades for the plant safety monitoring system (PSMS) and the validation of the PSMS base-scope were still in process.

The base-scope validation status on November 16, 1986 was established using a total number of 2243 test items for the QDPS system. The total number of validation trouble reports issued was 16. The total number of special-test trouble reports issued was 13. These trouble reports illustrated that there were very few real design or hard-code errors. The number of trouble reports issued at that date during the validation process was significantly smaller because the items were corrected as part of the verification process. The trouble report error types identified during the validation testing are still being identified and analyzed. It should be noted that supplemental "special tests" were performed as part of the validation process. This additional testing covered the unique requirements of the man-machine interface and prudency, which are not part of the QDPS functional requirements. A review of the trouble reports issued (during the validation process) indicated that discrepancies discovered could not have been found or identified during the verification process because the whole system needed to be on test (as was only done during the validation testing) for the problem to have been seen.

The methods utilized for resolution of the validation trouble reports were (1) software modifications, (2) hardware modifications, (3) the revision of test procedures, or (4) the revision of functional requirements. After a review of the validation program test results coupled with the statistical summary of the verification trouble reports by type, the following conclusions can be reached:

(1) The first audit report concluded that the deficiencies noted in the verification process at the design level would shift the discovery of discrepancies to the validation phase. In response to comments generated at the earlier audits, it was obvious that a greatly increased effort was devoted to the software verification process and problems were (and will be) resolved in the verification phase. The number of trouble reports generated through verification was more than 10 times the number generated during the validation process.

(2) The fact that 60% of the verification trouble reports were caused by insufficient documentation and inconsistent documentation serves to further emphasize the importance of independent verification of the design.

(3) An analysis of the 42 verification error codes supports the conclusion that structual as well as functional verification has been done as stated in the design verification and validation plan. This is important because recent studies have shown that functional testing alone is not adequate.

One problem that became apparent during the fourth audit review was the lack of one-to-one correspondence between the test shown in the functional requirements documentation and those actually performed. The applicant stated that part of the validation process was to evaluate the factory acceptance tests (FATs) to determine if further validation tests were required. The intent by the

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individuals decomposing the functional requirement was not to impose a stringent test requirement for the members of the validation team responsible for writing the test procedures. Instead, the intent was to define a test that would completely test the specified functional requirements. If the validators could identify an alternative FAT section or derive an alternative test so that the intent and/or objective of the functional decomposition was satisfied, that alternative is considered acceptable by the individuals decomposing the functional requirement. Hence, the validation engineer that initials and dates the validation sign-off sheet is responsible for determining that the specified validation test procedure meets the intent and/or objective of the functional requirement and suggested test description. The documentation of this issue (FAT) is discussed later in this section (Issue 7).

On the basis of the four audit reviews, the implementation of the validation plan was judged to be adequate.

Issue 2--Question of Independent Design Verification

As identified in the first audit report (letter to applicant dated January 30, 1986), the staff noted the lack of independent design verification within the design process. It is the staff's engineering judgment that the validation plan should be sufficiently broad in scope to address discrepancies in the design process and to account for the lack of independent, formal design verification. Therefore, on the basis of this judgment, the question of independent design verification within the design process was shifted to the validation plan. The details regarding the present status of the validation phase were presented at the third audit.

The response by the applicant is that the validation plan will be sufficiently broad in scope to address deficiencies in the design process and to account for the lack of independent formal design verification.

The staff's evaluation of the verification and validation plan as implemented supports this response:

(1) Verification and validation are performed on each software unit following uniform and exhaustive procedures. A test requirement was written from each sentence of the functional requirement. Four hundred to five hundred validation tests are being done, and each one is being signed off. Fail documents will be issued which will explain the failures and determine the corrective action to be taken.

(2) A design review process that evaluates the system's design methodology and implementation (referred to by Westinghouse as Prudency Design Review) has been added to the functional requirements testing. This review examines the software units for good software design and for any oversights in the implementation that would lead to the introduction of unexpected or incorrect results. Although the functional requirements testing will validate the software against the requirements, the prudency review incorporates many of the functions of a design review.

(3) The audit trail for verification will be strengthened by the broader validation plan.

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It is apparent that there has been a large commitment of time and money to perform verification and validation. The functional decomposition has been done in great detail. The coding decomposition from the test procedure documents corrects the problems noted in the first audit (e.g., lack of independent verification). The prudency review is a good addition during which the software's internal workings will be studied. This addresses the issue of independent verification. The staff confirmed that the validation plan had been properly executed during the fourth audit. Therefore, the staff has concluded that this issue is resolved.

Issue 3--Software Criticality

This issue was raised in the first audit because of the concern that the manpower and computer intensive V&V plan proposed could not be accomplished within the time and cost constraints. The response to this issue by the applicant was that the same level of V&V effort is directed toward all software units because of the interactions between QDPS subsystems software. An examination of the verification audit trail shows that the level of effort is the same for all units and that the verification and reverification is proceeding in a timely fashion. The trouble reports that document both lack of correspondence between code and documentation and software code problems are being cleared within a reasonable time frame.

On the basis of the information provided, the staff concludes that this issue is resolved.

Issue 4--Clarification of Physical Media and Verification of Program Listing

One of the open items in the audits was the verification of the physical media that represent the program. The verification of physical media means those activities performed to ensure that the burned-in programmable read only memory (PROM) contains the authorized program (i.e., security and safeguard measures).

The V&V team has control of the V&V configuration management system (CFMS), which contains the authorized programs. The programs are not directly accessible by the design teams. The V&V team controls the physical media (i.e., PROMs), which contain the programs used during the validation process and perform the following to ensure its integrity:

(1) downloading of the executable load module (i.e., hexadecimal (HEX) file*) from the V&V CFMS on the VAX 8600 computer system to the Intel PROM burner

(2) burning of PROMs

(3) verification that PROMs were burned correctly

(4) marking of the PROMs

*The HEX file contains checksum, which ensures that the program transfer to the PROM burner is accurate.

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(5) reverification of the PROMs against the HEX file after validation testing is complete to ensure that the PROMs still contain the proper HEX file programs

The staff found the strict configuration management procedures acceptable. However, the steps of manually labeling each PROM with the subsystem, the cabinet, the slot, and the unique version identifier did not entirely convince the staff that the correct version and the correct PROM would always be installed and not be subject to malicious mischief. The design did not take advantage of some of the capabilities of digital systems. Programmable systems are not only capable of executing diagnostics but also of reporting version identifiers, installation dates, and other information if so designed.

A procedure was implemented by the applicant and Westinghouse which produces computer-generated labels, one for the top and one for the bottom of each PROM. This label generation occurs at the same time the code is generated that is burned onto the PROM.

In addition, the applicant has performed a series of test to determine the consequences of incorrectly installing a PROM either inadvertently or through malicious procedures. These tests demonstrated that the machine would halt because of the checksum differences. The few instances where the machine did not halt and execution continued, it was shown by bit comparisons that the PROMs were, in fact, identical. This is expected to occur occasionally in such a highly redundant system. The following is a summary of the results of the tests performed:

PROM switch made	Result
Switch within control (on same board)	Halt (stop)
Switch a PROM set between control and SGWLCS, then initialize non-volatile random access memory and finally switch back the PROM set	Aborted by checksum diagnostics
Switch A PROM from control A to control B	System ran
Switch A PROM between control A to SGWLCS A	Halt (stop)

As a result of its review, the staff has concluded that generating a label by computer is a vast improvement over manually labeling each PROM and that adequate procedures and safeguards exist within the QDPS to detect and indicate PROM installation error or malicious mischief. Therefore, this issue is resolved.

Issue 5--Software Maintenance Practices

The applicant has committed to utilize the existing V&V program for all software maintenance/modifications until an in-house utility program has been developed and received appropriate staff approval. There appear to be strict control within the present V&V configuration management system and adequate procedures

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for issuing new system revisions. Therefore, this issue is resolved until the applicant provides changes in the software maintenance practice area.

Issue 6--User and Maintenance Documents

The staff examined detailed user and maintenance documents and found them to be adequate. Therefore, this issue is resolved.

Issue 7--Discrepancy Between the Functional Requirement Decomposition Test Description and the Actual Validation Test Conducted

The required additional information to resolve this issue was provided by the applicant in a letter dated December 23, 1986. This information is summarized below.

The functional decomposition consists of a line-by-line decomposition of the functional requirements associated with the QDPS. This decomposition was performed by engineers who were independent of the system design. The functional decomposition included the following information: (1) a validation reference number, (2) a listing of the appropriate functional requirement reference, (3) a line-by-line statement of the functional requirement being addressed, and (4) a suggested description of the test to be conducted to verify that the system meets the applicable functional requirement.

The functional decomposition is then utilized by a validation engineer to either (1) generate a test procedure or (2) identify a factory acceptance test (FAT) that meets the intent of the suggested test description. In general, Westinghouse found that tests that existed in the FAT exceeded the requirements of the suggested test. The intent by the individuals decomposing the functional requirements was not to impose a stringent test requirement for the members of the validation team responsible for writing the test procedures. Instead, the intent was to define a test that would completely test the specified functional requirements. If the validators could identify an alternative FAT section or derive an alternative test so that the intent and/or objective of the functional decomposition was satisfied, that alternative was considered acceptable by the individuals decomposing the functional requirement.

Hence, the validation engineer that initials and dates the validation sign-off sheet is responsible for determining that the specified validation test procedure meets the intent and/or objective of the functional requirement and suggested test description. On the basis of its review of the additional information provided by the applicant, the staff concludes that this issue is resolved.

Issue 8--Review of Final V&V Report

The fourth audit report (letter to applicant dated January 29, 1987) states, as a confirmatory item, that the staff is to review the final QDPS V&V report (letter dated December 23, 1986). The staff has reviewed the final QDPS V&V report and has confirmed that this report accurately reflects the material that was presented by Westinghouse and the applicant during the four staff audits. On the basis of this review, the staff considers this issue resolved.

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Issue 9--Final Summary of Trouble Reports

The fourth audit report (letter to applicant dated January 29, 1987) states that after the validation trouble reports have been completed, a copy of the summary of all of the trouble reports, similar to the verification summary table with summary numbers, should be provided. The applicant and Westinghouse should review each trouble report to determine whether these problems could have been found previously. The staff was to review these data and report its findings at a later date.

By letter dated March 19, 1987, the applicant provided Supplement 1 to the QDPS V&V final report. Supplement 1 indicates that the data have been analyzed for base scope and validation testing has been completed on the "upgrades." A total of 72 validation trouble reports have been issued identifying a total of 87 error types. Of the 87 error types reported, 81 have been resolved either through software changes, functional requirement changes, validation test procedure/decomposition modifications, hardware changes, or recognizing that the documented error was not a problem. The remaining six trouble reports require modifications to the display graphics and are still pending final implementation. These six trouble reports address use of incorrect acronyms, instrument tag mislabeling, and absence of engineering unit destination. The applicant has committed to resolve these trouble reports before South Texas Unit 1 begins commercial operation.

In addition to the trouble reports, a total of 30 clarification reports were issued on the base scope and upgrade activity. All clarification reports have been addressed and have been successfully cleared.

A review of all issued validation trouble and clarification reports by the applicant indicated that none of the errors identified would have been found during the verification process. The validation reports were in areas specific to validation testing. On the basis of its review of the information provided in Supplement 1, the staff considers this issue resolved.

Issue 10--QDPS Operational Data

The staff requested that the applicant inform the NRC staff of all troubles encountered and all changes made to the QDPS during the first operating cycle of the plant. This will provide the staff a basis for evaluating the reliability of the system. The applicant made this commitment in the QDPS V&V final report transmittal letter (letter dated December 23, 1986). Therefore, this confirmatory issue is resolved.

On the basis of the extensive review performed, the staff has concluded that the V&V procedures established by Westinghouse and the applicant for the QDPS are comprehensive and sufficiently address the requirements associated with the design and testing of highly reliable systems.

The staff's review of the validation information provided during the third and fourth audits restored confidence in the verification and validation of the QDPS and corrected the deficiencies noted in the first and second audits.

The staff's review has shown that the validators' plan presented at the third audit has been appropriately implemented and executed. In addition, the review

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has shown that the applicant's method for clarifying physical media and verifying the program listing is acceptable. Sufficient safeguards exist within the QDPS to detect and indicate PROM installation error or malicious mischief.

The staff has found that the V&V effort for the QDPS meets the guidelines established within ANSI/IEEE-ANS-7-4.3.2.-1982, "Application Criteria for Programmable Digital Computer Systems in Safety Systems of Nuclear Power Generating Stations," and IEEE Standard 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations." Thus, it is the staff's judgment that the V&V effort for the QDPS at South Texas is acceptable and this portion of the open issue regarding the QDPS is resolved.

7.5.2.6 Qualified Display Processing System Interface With Class 1E Control System

As discussed in the SER, because the applicant had not fully documented the QDPS design, the staff had postponed the review of the QDPS interface with Class 1E control systems until the required information was provided by the applicant. Since the publication of the SER, the staff has reviewed the various amendments to the FSAR, a letter from the applicant dated October 4, 1985, and the information provided in the four verification and validation audits conducted by the staff (letters to the applicant dated January 30, May 19, and October 7, 1986 and January 29, 1987) and has formulated the following conclusions regarding this portion of the QDPS design.

The qualified control system function within the QDPS performs valve control actions including (1) closed-loop control and position indication for the steam generator power-operated relief valves, (2) contact output signals for automatic control and position indication of auxiliary feedwater control valves within the upper and lower flow limits, (3) open-loop control and position indication for the reactor vessel head vent valves, and (4) closed-loop control and position indication for essential cooling water flow control valves to safety-related heating, ventilation, and air conditioning (HVAC) chillers. The staff reviewed the block diagrams for these four QDPS control functions and decided to choose a control function to review during the second V&V audit (letter to applicant dated May 19, 1986).

To conduct the audit, the staff reviewed a thread of design information to evaluate the qualified control system. Specifically, a sensor signal was selected, and the signal was then followed from the sensor through the hardware and software components of the QDPS until an interface with another system/component was reached. Design documentation in the form of wiring diagrams, technical data sheets, and computer program listings were used to trace the signal and evaluate the operations on it. Furthermore, the staff requested that Westinghouse personnel identify points in the thread where design V&V activities had occurred or were planned.

The above audit method was used to trace a flow transmitter's signal through the qualified control system function within the QDPS. This signal measured auxiliary feedwater flow. The review of this thread was terminated at the interface of the QDPS and the auxiliary feedwater control valves.

On the basis of its review of (1) the control loop diagrams for the four QDPS control functions, (2) the detailed audit of the thread design information for

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one control function, and (3) the information provided in the FSAR and its amendments (through Amendment 56), the staff concludes that the QDPS interface with the four Class 1E control functions is acceptable and meets staff requirements and guidelines regarding Class 1E control interfaces. Therefore, this portion of the QDPS open item is resolved. It should be noted that the staff review of the adequacy of the isolation devices used to interface the safety-related and non-safety-related systems within the QDPS will be discussed in Section 7.5.2.9 of a future supplement.

7.5.2.7 Qualified Display Processing System Interface With Alternate Shutdown Capability

The QDPS is used to provide data acquisition, display, and a limited number of control functions that are transferred to the auxiliary shutdown panel and other local control points following a control room fire. Because the QDPS design had not been completed, the evaluation of alternate shutdown capability was listed as an open item in the SER. The applicant has completed the QDPS design and has provided information regarding the final alternate remote shutdown capability design at South Texas. This information was provided through meetings and by several amendments (e.g., 41, 53, and 55) to the FSAR.

The auxiliary shutdown panel (ASP) is located in the electrical auxiliary building (EAB) at elevation 10 feet. Both Class 1E and non-Class 1E controls and indicators are provided. Acceptable electrical separation is maintained between separation groups within the panel in accordance with Regulatory Guide 1.75 criteria. The controls on the ASP are electrically isolated from those in the control room by transfer switches located on the transfer switch panels with the exception of the controls associated with the turbine-driven auxiliary feedwater pump train and associated flow regulation controls which are located on the ASP. Safety-related display on the ASP is provided by the QDPS. Both the A and C database processing units transmit the monitoring information via datalinks to plasma display units (A and C) located on the ASP. In addition, the QDPS provides the control functions for the reactor vessel head vent valve control, the auxiliary feedwater flow control, the essential cooling water flow control to the safety-related HVAC chillers, and steam generator power-operated relief valve control. The controls and monitoring indicators provided at the ASP are identified by the applicant in FSAR Table 7.4-1. The monitored parameters available via the QDPS are identified in FSAR Table 7.5-1.

The six transfer switch panels are located in the EAB, and two of the panels are located in each of their associated switchgear rooms at elevations 10 feet, 35 feet, and 60 feet. The transfer switch panels provide control transfer between the control room and the ASP control circuits. In addition, control is provided on the transfer switch panels for equipment that requires one-time or infrequent control during safe shutdown. The transfer switches and controls provided on the panels are identified in FSAR Table 7.4-2. The switches and controls provided on the transfer switch panels are Class 1E. Acceptable electrical and physical separation has been maintained between the separation groups. Transfer of control from the control room is alarmed and indicated in the control room.

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In addition to the controls and indicators provided at the ASP and transfer switch panels, the following controls are provided outside the control room:

(1) reactor trip capability, provided at the reactor trip switchgear

(2) start/stop controls and transfer switches for the standby diesel generators, located on each diesel generator local panel

(3) start/stop controls for the essential chillers, located on each essential chiller local panel

(4) start/stop controls and transfer switches for the essential cooling water intake structure ventilation fans, located at motor control centers

(5) open/close controls for various support equipment not requiring immediate or constant control, located at motor control centers

(6) disconnect switches for solenoid valves to fail open or closed (depending on application) air-operated valves, located at the auxiliary relay cabinets

Communications are provided between the ASP, the control room, switchgear rooms, and the technical support center via the dc-powered headset system.

As a result of its review, the staff has concluded that the ASP at South Texas is a safety-related system, and that the design includes adequate redundant controls and display instrumentation (QDPS) that are safety grade, which provides the operator with the capability to promptly achieve and maintain hot shutdown from locations remote from the control room. In addition, the design includes the capability for obtaining subsequent cold shutdown through the use of suitable procedures.

In summary, the staff has reviewed the applicant's ASP design including the QDPS interface features and has concluded that it meets the regulatory requirements in GDC 19 and the guidance in SRP Sections 7.4.II and III (NUREG-0800). Therefore, this portion of the QDPS open item is resolved.

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8 ELECTRICAL POWER

8.1 Introduction

In the SER, the staff stated that it would review electrical drawings and visit the site to view the installation and arrangement of electrical equipment and cables to verify the proper implementation of the design as described in the FSAR. The staff visted the site on January 28-30, 1987, at which time certain concerns were identified. These concerns were discussed with the applicant and identified in the staff's meeting and summary of February 20, 1987. The staff's evaluation and the applicant's proposed modifications or justification are discussed below. The evaluation of Open Item 9 identified in the SER is discussed in Section 8.3.3.3.3 of this supplement.

Identification of Class 1E Equipment

During the site visit the staff observed the implementation and color-coding schemes for safety-related circuits and equipment. It found that many safety-related pumps were not identified. The staff required the applicant to identify the above pumps and to check other electrical equipment to ensure this condition does not exist elsewhere in the plant.

By letter dated March 11, 1987, the applicant stated it has developed a procedure for an equipment-labeling program that will be implemented at South Texas by the Plant Operations Department. This procedure will ensure that all components are permanently labeled with an identifying tag or plate to provide operators and maintenance personnel with sufficient information for positive identification. The labels for equipment located inside the containment building will be made of stainless steel. Aluminum labels used outside the containment will be color coded according to the South Texas color-coding scheme for safety-related and non-safety-related trains. On the basis of the above, the staff finds this concern resolved.

Containment Penetration Splices

As part of the walkthrough of the containment penetration areas, the staff found that many low power cable penetration terminations (splices) were inadequately installed in that both ends of the splices were not sealed properly. The staff required the applicant to develop a program to inspect all safety-related splices located inside and outside the containment for connecting field wiring to the electrical penetration conductor and to initiate replacement of splices if they were found to be improperly installed.

By letter dated March 27, 1987, the applicant stated that all safety-related terminations (splices) inside and outside the containment are documented in a computerized cable report. The termination documentation associated with the cable-to-cable splices in this report was reviewed to verify that materials used in the Raychem splice conformed to the vendor's installation instructions. As a result of this review, the applicant identified a total of 22 cable splices, including those found by the staff, that were found to be deficient. These

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22 splices will be reworked so that they will conform to the vendor's installation procedures. This item has been reported to the NRC staff pursuant to 10 CFR 50.55(e).

In a discussion with the applicant on April 9, 1987, the staff informed the applicant that a documentation review of the penetration termination is not enough and that a visual inspection of the penetration termination (splices) inside and outside the containment is warranted.

Subsequently, in a letter dated April 10, 1987, the applicant committed to institute a program to inspect randomly a sample of 10% of the Class 1E splices installed to connect field wiring to the penetration conductors (inside and outside the containment). However, in a discussion on April 21, 1987, the applicant informed the staff that as a result of its penetration termination documentation review and visual inspection of the safety-related in situ penetration terminations (splices), approximately 350 cable splices have been found to be deficient rather than 22 as was reported earlier. Further, 1230 splices have been found to conform with the vendor's installation instructions (1010 by documentation review and 220 by visual inspection) and approximately 420 splices need further evaluation. Of 420 splices, 230 will be visually inspected and 190 will undergo documentation review.

On the basis of the above, the staff concludes that 1 out of 6 (350 out of 2000) improperly installed penetration cable splices provides sufficient evidence of inadequate installation. Additional inspection of the penetration splices will be required. The deficiencies in the installation of cable splices could result in failure of Class 1E equipment essential to the safe operation and shutdown of the plant. Therefore, considering the high rate of improperly installed penetration splices, the staff requires the applicant to perform a visual inspection of all penetration splices located inside and outside the containment and to rework all splices that do not conform with the vendor's installation instructions. The followup review and resolution of this item will be performed by Region IV staff.

Physical Separation Between Heat Tracing Circuits and Non-Class 1E Circuits

The staff's walkthrough of the engineered safety features pump rooms revealed that the physical separation between Class 1E heat tracing circuits and non-Class 1E circuits does not meet Regulatory Guide (RG) 1.75. The staff required the applicant to perform an analysis to demonstrate that the existing separation between the above circuits is adequate.

By letter dated March 27, 1987, the applicant submitted an analysis on the above subject. The staff has reviewed this analysis and concludes that the resistance temperature detector (RTD) circuits are low-energy circuits that cannot affect the Class 1E heat tracing circuits. RTDs are temperature-sensitive devices used to monitor the temperature of components such as motor windings and pipes. 600-V rated cables consisting of shielded twisted triads connect RTDs to signal conditioners. Signal conditioners use wheatstone bridges, of which the RTD is one leg, driven by a power supply. Because of the wheatstone bridge's inherent configuration and operating characteristics, a fault on the RTD cable is limited to values identical to the normal operating current of 20 ma. On the basis of the above, the staff finds the existing design acceptable.

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Identification of Battery Pilot Cells

The staff's walkthrough of the battery rooms revealed that the pilot cells were not identified and that the markings on the pilot cells were not labeled as "maximum" and "minimum." The staff required the applicant to identify and mark the pilot cells properly for each Class 1E battery.

By letter dated March 27, 1987, the applicant stated that a station procedure has been developed for the 7-day surveillance test of the 125-V Class 1E batteries. This procedure specifically states that the electrolyte level of the designated pilot cell is to be above the bottom line and less than 1/4 in. above the top line rather than the maximum and minimum level. The data sheet, which must be completed, also refers to the "top line" and "bottom line."

With regard to the identification of pilot cells, each battery cell in a battery bank has a number on it that distinguishes it from all other cells in the bank. Each year the plant computer generates a new selection of pilot cells. During the 90-day surveillance testing, a new selection of pilot cells is made. Thus, numbers affixed to each battery cell ensure positive identification of those selected as pilot cells.

On the basis of the above, the staff finds the existing design acceptable.

Valve Position Indication for Accumulator Valves

The staff's review of the control circuitry of the passive safety-related valves revealed that if the power to these valves is locked out, redundant valve position indication is not provided for such valves. The staff required the applicant to provide redundant valve indication for these valves or justify the present design.

By letter dated March 27, 1987, the applicant stated that two redundant valve position indications have been provided for the accumulator discharge isolation valves. One set of indicating lights is operated by limit switches within the valve operator powered from the 480/120 V ac control transformer in the motor control center. The redundant set of indicating lights is operated by stem-mounted limit switches on the valve, powered from a different 120 V ac source. However, the redundant position indications for these valves are available only when the valve operator has power available. This is because the indicating light powered from the 480/120 V ac control transformer in the motor control center goes off when the power to the valves is locked out. The applicant has indicated that since the valve position indication for these valves is verified correct before power is locked out, the valve position cannot change while power is locked out. Moreover, the valve position can always be confirmed by temporary reapplication of power.

In addition to the above redundant valve position indications, non-Class 1E computer indication and an alarm are provided in the control room when valves are not fully open. On the basis of the above, the staff finds the valve position indication for these valves acceptable.

Primary and Backup Protection for Penetration Control Circuits

The staff's review of the circuits for penetration protection revealed that, for certain control circuits, primary and backup protection is not provided.

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The staff required the applicant to either provide primary and backup protection for these control circuits or justify the present design.

By letter dated March 27, 1987, the applicant stated that since the fault currents for these circuits are limited to below the continuous current-carrying capability of the penetration conductors because of the impedance of the control transformers, only a single protective device is necessary. For these circuits, the staff believes that although the impedance of the control transformer limits the short circuit current to below the continuous current-carrying capability of the penetration conductors, these control transformers cannot limit the fault current indefinitely.

Subsequently, by letter dated April 8, 1987, the applicant further justified its position for providing single protection for control transformer circuits. The applicant indicated that even if the primary and secondary winding welded together so that the secondary can see the 480-V system voltage and short circuit currents, the penetration will still be protected. Since the 480-V system is an ungrounded system (delta connected), a short of one primary conductor to one secondary (120-V) circuit would result in cable charging current (0.5 to 5 A) that is less than the penetration conductor rating (31 A).

A short of both primary (480-V) terminals to both secondary terminals of the control power transformer would result in 480 V applied to the penetration conductor circuits. An analysis has shown that the primary 480-V breaker will provide backup protection for the penetration conductors in this case and the penetration will be protected.

On the basis of the above, the staff concludes that one line of overcurrent protection for these circuits is acceptable.

Independence of Offsite Power Circuits

During the site visit, the staff informed the applicant that the design of the offsite power system is not electrically independent as required by SRP Section 8.2.1.1 (NUREG-0800). The control power for the 13.8-kV switchgear that supplies offsite power to South Texas is from a single battery. The staff required that the control power for the switchgear be from separate batteries.

By letter dated March 27, 1987, the applicant requested that this item be treated as a deviation to the SRP with corrective action to be implemented by the first refueling outage. The corrective action will be to supply redundant sources of control power to the 13.8-kV switchgear to meet the requirement of SRP Section 8.2.1.1. The staff finds the applicant's commitment to implement the design modifications by the first refueling acceptable for the following reasons:

(1) On a loss of control power, the breakers stay in the closed position.

(2) The breakers can be manually operated if needed.

(3) The control power to the incoming breakers to the Class 1E buses is supplied by redundant Class 1E batteries. Thus, on loss of offsite power, these breakers will open and the standby diesel generators will connect to their respective buses.

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(4) The staff feels that the probability of a loss-of-coolant accident coupled with a fault on the offsite circuit and a failure of the 125 V dc switchgear battery occurring simultaneously during this time period is highly unlikely.

8.3 Onsite Power System

8.3.3 Compliance With GDC

8.3.3.3 Physical Independence (Compliance With GDC 17)

8.3.3.3.3 Raceway and Cable Separation

In the SER, the staff stated that the aluminum- and copper-sheathed (ALS and CS) cables that are of continuous, seamless, water-impervious, metallic sheath construction can be used as totally enclosed raceways, in compliance with the separation requirements of Position 2 of RG 1.75, "Physical Independence of Electrical Systems," provided the minimum separation distances of these raceway systems not meeting the requirements of RG 1.75 can be justified by an analysis based on tests. The applicant committed to test these cables and submit the test results for the staff's evaluation.

By letter dated February 19, 1987, the applicant submitted a copy of Wyle Laboratories Report No. 53575 to support its compliance with RG. 1.75. This Wyle test report contains the test program methodology and the test results for the ALS and CS cables. The revised separation distances are derived from Wyle test results and are being implemented in the South Texas plant.

Before initiation of the testing phase of the program, the applicant developed a test procedure that formed the basis of the tests. In order to perform a test program to verify the adequacy of the raceway separation criteria, the test procedure defined the worst-case electrical failure that could be postulated to occur in a raceway. This worst-case electrical failure was based on the following failure mode assumptions:

(1) A fault current level is assumed to be just below the long time trip setpoint of the circuit secondary (upstream) overcurrent protective device so that the fault is not cleared.

(2) The fault current is conservatively maintained at a constant level until conductor open circuits or steady-state conditions are reached.

Before the beginning of each cable overcurrent (fault) test, baseline tests of target cable were performed. They consisted of insulation resistance measurement and a 1-minute high potential test. At the completion of the cable overcurrent test, post-overcurrent tests consisted of the insulation resistance measurements and a 1-minute high potential test. The acceptability of the test was based on the condition that the target cable pass the post-overcurrent tests, as well as show no physical damage.

The Wyle program with the above inputs and assumptions for the target cables demonstrated the acceptability of the raceway design for the various configurations as detailed in the Wyle test report (No. 53575).

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Also in this test program the following configurations were demonstrated to be unacceptable because the target cable showed physical damage:

(1) One test consisted of passing a 600-amp fault current through a 3/C #4 cable in liquidtight Anaconda flexible conduits with a PVC jacket and separated 1 in. vertically from target cables 4/C #16, 1/C #14, and 3/C #10 all bundled together in free air.

(2) The second test consisted of passing a fault current through a 4/C #6 power cable in free air separated 1 in. vertically from target cables 1/C #16, 1/C #14, and 3/C #10 all in Anaconda sealtight flex conduit with PVC jacket.

(3) The third test involved a faulted free air cable and target cables in a covered tray having a 1/2-in. gap between the tray and the tray cover.

Two subsequent tests were conducted by Wyle (one test with the fault cable in the flex and the other test with the target cables in the flex) to demonstrate that the Anaconda sealtight flexible conduit will meet RG 1.75 separation criteria provided a 9-in. horizontal separation in conjunction with any vertical separation between target cables and fault cables with 600 amps applied is maintained. Similarly, another test, with a fault cable in the Anaconda flexible conduit separated by 1 in. from three target cables in free air, demonstrated that, with 325 amps applied to the fault cable, the Anaconda sealtight flexible conduit meets RG 1.75.

For item 3 above, it was concluded that a 9-in. horizontal separation must be maintained between the faulted cable and the 1/2-in. gap in the tray covers.

The applicant is conducting a walkdown of Class 1E and non-Class 1E installations using the Anaconda sealtight flexible metal conduits to determine the number of installations that do not conform to the revised acceptable separation list. For any cable configuration that does not meet the revised separation criteria, appropriate corrective action will be taken to ensure conformance to RG 1.75.

On the basis of the above, the staff concludes that, with the exception of the configuration of item 2 above and the proper implementation of the revised criteria established for items 1 and 3 above, the minimum separation distances of the raceway system not meeting the requirements of RG 1.75 have been justified by testing and analysis (for configuration detailed in Wyle Test Report No. 53575), and therefore are acceptable.

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9 AUXILIARY SYSTEMS

9.1 Fuel Storage and Handling

9.1.2 Spent Fuel Storage

By letter dated March 16, 1987, the applicant requested an exemption from the provisions of 10 CFR 70.24 in the operating license for South Texas Unit 1. The particular provisions for which an exemption is requested relate to the presence of a criticality monitor in the fuel storage area. The staff has reviewed the request and prepared the following evaluation.

An exemption to the requirement for criticality monitors in the fuel storage areas was provided in Materials License No. SNM-1972, which authorized the receipt, possession, inspection, and storage of fuel assemblies containing U-235 (among other things). The bases on which the exemption was granted for the materials license are also valid for the operating license. These include the following:

(1) The fuel storage racks provide physical protection to prevent criticality.

(2) Fuel handling activities will follow previously written and approved procedures.

(3) No more than two assemblies will be allowed out of storage at any time (for this purpose storage includes the reactor vessel).

(4) Separation between the two fuel assemblies out of storage will be maintained by requiring that they be in separate areas.

The staff concludes that the granting of the requested exemption is acceptable.

9.5 Other Auxiliary Systems

9.5.1 Fire Protection

9.5.1.1 Fire Protection Program Requirements

Fire Protection Program

Generic Letter 86-10, "Implementation of Fire Protection Requirements," dated April 24, 1986 states that the inclusion of the fire protection program in the FSAR is a prerequisite for licensing for all applications now under review. By letter dated March 26, 1987, the applicant submitted revised FSAR sections incorporating the fire protection program that has been approved by the staff into the FSAR by reference, and includes a commitment to establish limiting conditions for operation, action statements, and surveillance requirements for the fire protection program. The applicant stated that these procedures will

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provide a level of protection equivalent to that in the fire protection sections of the Westinghouse Standard Technical Specifications (STS) (NUREG-0452) with acceptable clarifications.

This revision to FSAR Section 9.5-1 meets the guidance for operating license applications currently under review as set forth in Generic Letter 86-10. On this basis, and on the basis that the applicant's procedures will encompass the surveillance procedures and action statements of the STS, the staff concludes that the FSAR revision submitted by the applicant in its March 26, 1987 letter is acceptable.

9.5.1.4 Generic Plant Guidelines

Building Design

Section D.1.j of Appendix A to Branch Technical Position (BTP) APCSB 9.5-1 (NUREG-0800) states that floors, walls, and ceilings enclosing separate fire areas should have a minimum fire rating of 3 hours including penetration seals, fire doors, and dampers. In the SER, the staff stated that barriers enclosing separate fire areas at South Texas have a minimum fire resistance rating of 3 hours except where deviations have been evaluated by the staff and found acceptable.

In Section 4.2 of the Fire Hazards Analysis Report (FHAR) and in a letter dated March 11, 1987, the applicant stated that exterior walls and/or ceilings that serve as fire area boundaries are not rated except where significant fire exposures exist within 50 feet.

As part of the fire hazards analysis, the applicant has determined that no significant fire hazard exposure exists within 50 feet of an unrated exterior fire area boundary. The exterior walls, ceilings, and floors are of substantial noncombustible construction and, although not rated, provide substantial fire separation of safety-related areas from exterior yard areas.

Providing rated exterior boundaries would not significantly increase the level of separation between fire areas. It is the staff's judgment that the exterior fire area boundaries will withstand the hazards present and prevent the spread of fire from one fire area to another. Therefore, the lack of 3-hour-rated exterior fire area boundaries where no significant fire hazard exists within 50 feet is an acceptable deviation from Section D.1.j of Appendix A to BTP APCSB 9.5-1.

In the March 11, 1987 letter and in the FHAR, the applicant identified three fire dampers (FF-036, FF-367, and FF-368) located in ducting within fire area 7 that are not installed in accordance with manufacturer's instructions and are, therefore, not clearly fire rated.

Fire area 7 is the auxiliary shutdown panel (ASP) area. It is adjacent to the qualified display processing system (QDPS) cubicles (fire areas 2, 8, and 9). The heating, ventilation, and air conditioning (HVAC) supply and return air ducting for all QDPS cubicles and the ASP area is common and is located entirely in the ASP area (fire area 7). To ensure the availability of HVAC to the QDPS cubicles for a fire in the ASP area, the common ducting located in the ASP area is enclosed in 3-hour-fire-rated material.

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Because of the installation of this material on the common ducting, fire dampers within the supply and return duct outlets from the ducting that serve fire area 7 could not be installed in accordance with manufacturer's recommendations. The manufacturer provided details for installing fire dampers in typical barriers, such as masonry walls, that are not applicable to the installation of dampers FF-036, FF-367, and FF-368. To protect these damper installations, the 3-hour-fire-rated barrier material is attached to the outside of the ducting and extends over and includes the portion of the ducting housing these dampers.

The combustible loading in the QDPS cubicles and the ASP area is low, consisting primarily of cable insulation. Each QDPS cubicle and the ASP area are protected by ionization smoke detectors that alarm in the control room.

Because the combustible loadings are low, the staff does not expect a fire of significant magnitude or duration to occur. If a fire should occur, there is reasonable assurance that it will be detected in its early stages by the smoke detectors installed and alarmed in the control room. Operators could then take appropriate actions to minimize the effect of the fire. The installation of the 3-hour material on the ducting and fire dampers FF-036, FF-367, and FF-368 will prevent fire propagation to adjacent fire areas until the fire is extinguished by the fire brigade.

On these bases, the staff concludes that the installation of fire dampers FF-036, FF-367, and FF-368 is an acceptable deviation from Section D.1.j of Appendix A to BTP APCSB 9.5-1.

Also in the March 11, 1987 letter, the applicant requested a deviation for the essential cooling water (ECW) pump areas for Units 1 and 2. Fire areas 53, 54, 55, 56, 57, and 58 are the ECW pump rooms for Units 1 and 2 in the ECW pump house. These fire areas are located in series; separated from each other by 3-hour-fire-rated barriers except for a sluice trough common to each pump room.

The sluice trough is separated from safe shutdown equipment within each fire area by heavy concrete construction. The areas on either side of the trough and on either side of the fire wall through which the trough passes have low combustible loading. The trough itself is void of combustible materials.

Ionization smoke detectors are installed within each fire area. If a fire occurs, it should be detected in its incipient stages and alarmed in the main control room. The fire brigade will be dispatched to extinguish the fire with portable extinguishers or manual hoses.

Until the fire is extinguished, the substantial barriers between fire areas, the lack of intervening combustible materials, and the low combustible loading within and adjacent to the sluice trough will provide sufficient passive protection to ensure that a fire within these areas would not spread to an adjacent fire area. On the basis of its review, the staff concludes that the installation of a common sluice trough through fire areas 53, 54, 55, 56, 57, and 58 is an acceptable deviation from Section D.1.j of Appendix A to BTP APCSB 9.5-1.

NFPA 80 of the National Fire Protection Association, "Standard for Fire Doors and Windows," provides guidelines for the installation of fire doors and door

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openings in fire barriers. NFPA 80 guidelines include limitations on clearance gaps between fire doors and frames, and fire doors and floors. There was concern that if clearance gaps in excess of those permitted by NFPA 80 existed around fire doors, an unacceptable fire propagation path may exist between fire areas.

During the plant site audit, the staff asked the applicant to confirm that fire doors installed at the plant met the clearance gap guidelines in NFPA 80. The applicant provided test reports (WHI-495-0799 and WHI-495-0800) of fire endurance and hose stream testing of fire-rated door assemblies installed with clearances in excess of NFPA 80 limitations. The reports were attached to the applicant's letter dated March 23, 1986. The make and model of the fire doors used at South Texas are the same as those used in the tested fire door assemblies.

The fire tests on the subject doors were conducted in conformance with Underwriters Laboratories, Inc. (UL) and NFPA guidelines and acceptance criteria. The fire-rated door assemblies described in the report successfully passed 3-hour-fire tests in accordance with the performance criteria specified by the American Society for Testing and Materials, UL, and NFPA except that the doors were installed with excessive clearances around their perimeters.

On the basis of the results of these tests, the staff concludes that because the applicant's fire door installations are comparable to the type tested and the as-built clearances are within those of the test installation, the existing fire doors provide a level of fire protection equivalent to that achieved by compliance with Section D.1.j of Appendix A and are, therefore, acceptable.

In the FHAR, the applicant states that fire areas 4 and 33 are bounded by 3-hour-rated fire barriers. During the plant site audit, the staff observed hollow-metal fire doors installed horizontally in the fire area boundary floor between fire areas 4 and 33. The doors are UL labeled for a fire rating of 3 hours. The typical configuration for the acceptance testing of UL-labeled, fire-rated doors is vertical. The staff asked the applicant to provide the basis for the use of these doors in a fire area boundary floor.

The applicant identified five hollow-metal fire doors (EAB-A, EAB-B, EAB-C, EAB-D, and EAB-E) installed horizontally in fire area boundary floors. The applicant stated that the horizontal installation of these doors is not representative of the vertical fire tests on which UL labeling is based; however, their use in a fire area boundary is acceptable on the basis of the results of an engineering evaluation.

In the fire zones adjacent to each horizontal door, smoke detectors are provided above the doors, and detection and automatic sprinklers are provided below the doors. The fire zones above each door are generally rooms with low combustible loading. Minimum combustible materials are located near the doors. The automatic sprinkler system in the zone beneath each door reduces the potential for significant fire exposure to the doors from below.

In the event of a fire adjacent to the doors, the fire detection system would operate an alarm in the control room during the period of slow fire growth. The fire brigade would then be dispatched to manually protect the door opening and to extinguish the fire. If a significant fire involving combustible

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materials below the doors occurs, the automatic sprinklers would operate and control the fire until the fire brigade arrived.

In the staff's judgment, effective fire brigade response and actions can be taken before the fire can reasonably be expected to propagate between fire areas. Moreover, the fire protection features provided in the adjacent areas and the inherent fire resistance of the doors provide reasonable assurance that a fire would be contained until the fire brigade arrived. On these bases, the staff concludes that the existing fire doors installed horizontally provide a level of fire safety equivalent to staff guidelines and is, therefore, an acceptable deviation from Section D.1.j of Appendix A to BTP APCSB 9.5-1.

During the plant site audit, security hardware modifications to UL-labeled fire doors installed in fire area boundaries were observed. The staff was concerned that because of the security modifications, the doors did not specifically meet the construction criteria of UL-labeled fire doors.

The applicant stated that the security hardware for fire doors was installed at the factory and that the doors were not field modified; therefore, the modifications do not affect the UL label affixed to the doors by the manufacturer.

Exceptions to the above factory-installed security hardware exist. They are the special-purpose doors serving the control room that were modified in the field in accordance with the manufacturer's instructions. At the plant site audit, the applicant confirmed that the field modifications do not adversely affect the fire rating and that the manufacturer has certified that the 3-hour rating on these doors is in effect.

On the basis of the above, the staff concludes that the security hardware on fire doors and the field modifications to the control room special-purpose doors do not affect their fire rating, and, therefore, meet the guidelines of Section D.1.j of BTP APCSB 9.5-1.

During the plant site audit, the staff asked the applicant to identify any steel hatchways for equipment removal, or other purposes, installed in floors which are required to maintain the 3-hour-fire rating of fire area boundaries in accordance with Section D.1.j of Appendix A to BTP APCSB 9.5-1.

In response, the applicant stated that there are no steel hatchways installed in the plant required to maintain the fire rating of fire area boundaries. This conforms to the staff guidelines and is, therefore, acceptable.

In the FHAR, the applicant states that fire areas 25 and 26 (charging pump rooms 1B and 1A) are bounded by 3-hour-rated walls, ceilings, and floors. Removable block wall sections form part of the fire walls serving as fire area boundaries for these areas. During the plant site audit, the applicant could not provide test data or an engineering evaluation supporting the 3-hour rating of these removable block wall sections. By letter dated April 17, 1987, the applicant stated that the walls have been evaluated for equivalency to a 3-hour-rated fire wall.

The removable block wall section design consists of solid concrete blocks,. stacked to full wall depth. The stacked blocks are typically retained in the

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barrier opening by steel framing anchored to each side of the fire barrier. The stacked blocks are cut to fit the opening and are staggered vertically and horizontally.

Because these removable wall sections are not rated and because the adjacent fire areas are not provided with automatic suppression, there was concern that a fire could propagate through the removable wall sections and affect plant safety.

However, the combustible loading in fire areas 25 and 26 and adjacent fire areas is low. Both fire areas are provided with ionization detectors that alarm in the control room. The solid block thickness of the removable wall sections exceeds the thickness required for a 3-hour-rated concrete or solid block fire wall. The seams of the stacked blocks are staggered vertically and horizontally between courses restricting the passage of flame and hot gases.

Because the combustible loadings are low, the staff does not expect a fire of significant magnitude or duration to occur. If a fire should occur, the fire detection system will detect a fire and alarm in the control room. The substantial construction and inherent fire resistance of the removable wall sections will provide passive protection against the spread of fire between fire areas until the fire is extinguished.

On these bases, the staff concludes that the installation of removable wall sections in the fire area boundaries of fire areas 25 and 26 is an acceptable deviation from Section D.1.j of Appendix A to BTP APCSB 9.5-1.

During a meeting on March 18, 1987, the applicant stated that the penetration seal design used for seismic wall and floor gaps in fire area boundaries may not be fire rated in accordance with staff guidelines. The material used to seal seismic gaps at South Texas is combustible and is not fire rated in the thickness and depth normally used. The staff was concerned that, because of the lack of rated seismic gap penetrations seals, a fire could propagate between fire areas through the installed seismic gap seals.

During the plant site audit, the staff asked the applicant to provide additional information regarding the fire rating of seismic gap penetration seals. The applicant stated that existing seismic gap seals containing 12-in.-depth applications of the combustible material in required fire area boundaries are being removed. The seals are being replaced with approved fire-rated seals conforming to staff guidelines.

Concurrently, the applicant is evaluating the existing seismic gap seal installations in thicker applications to determine the acceptability of either of the following:

(1) demonstrating that the existing penetration seal designs without modification are 3 hour fire rated in the thickness and depth installed

(2) modifying the thicker applications of the existing penetration seal design with additional approved fire seal material to form a 3-hour-rated penetration seal

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The evaluation of the above involves the fire testing of several penetration seal details for seismic gaps. The tested seals will serve as the boundary conditions for the acceptability of any seals used. The testing is being performed by a nationally recognized laboratory in accordance with standard fire test procedures and acceptance criteria.

Once the fire test program and any required modifications are completed, which the applicant committed will be done by fuel load, then the seismic gap penetration seals will be 3 hour rated in accordance with staff guidelines and, therefore, are acceptable.

Section D.1.f of Appendix A to BTP APCSB 9.5-1 states that concealed spaces should be devoid of combustible materials. In Table 4.2 of the FHAR and in a letter dated March 11, 1987, the applicant identified three fire zones with combustible materials concealed above suspended ceilings: fire zone Z034 in fire area 1 and fire zones Z147 and Z036 in fire area 3.

In the SER, the staff stated that, with the exception of cables located above the control room suspended ceiling (fire zone Z034 in fire area 1), concealed spaces above suspended ceilings are devoid of exposed combustible materials. In Section 9.5.1.6 of the SER, the staff found that concealed combustible materials above the ceiling of fire zone Z034 was an acceptable deviation from staff guidelines. During the plant site audit, the staff reviewed the combustible materials above fire zone Z034. Plywood, not identified in the FHAR, was observed on the floor of the ceiling above the control room. By letter dated April 8, 1987, the applicant committed to remove the plywood from this zone at turnover to the Operations Department.

The applicant stated that fire zones Z147 and Z036 in fire area 3 contain combustible materials in concealed spaces that were not addressed in the SER. Fire area 3 is a multielevation area of the mechanical-electrical auxiliary building. Fire zone Z147 consists of locker rooms and clothing issue areas; fire zone Z036 consists of corridors and offices on elevation 35 feet.

The combustible materials installed above the suspended ceiling in fire zone Z147 consist of cable tray sections. The slab above the suspended ceiling is provided with ionization detectors, and line-type heat detectors are installed on the concealed cable trays. An automatic sprinkler system is provided below the ceiling and in those portions of zone Z147 above the suspended ceiling containing the trays.

In the event of a fire in zone Z147, the fire detection system would activate an alarm in the control room. The fire brigade would then be dispatched to extinguish the fire. If the fire involves cables located above the suspended ceiling, the automatic sprinkler system is available to control the fire until it is put out by the fire brigade.

In the staff's judgment, the fire protection features provided for this zone provide reasonable assurance that a fire involving the concealed cable trays above the suspended ceiling in fire zone Z147 would be detected in its incipient stage and controlled. On this basis, the staff concludes that the installation of combustible materials above the ceiling in zone Z147 represents an acceptable deviation from Section D.1.f of Appendix A to BTP APCSB 9.5-1.

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Fire zone Z036 consists of the corridor and offices outside the control room on elevation 35 feet. FHAR Amendment 4 indicates that fire zone Z036 has a suspended ceiling with ionization detection provided below.

During the plant site auidt, the staff observed that the corridors of fire zone Z036 are not provided with a solid ceiling but with an all-metal, open-grid, lattice-type ceiling through which the slab and combustible materials above can be seen. The combustible materials located above the ceiling consist of cable tray sections. Smoke detectors are provided on the slab above the trays and can detect a fire from above or below the open lattice ceiling. Because of the visibility through the ceiling, fire brigade members would have little difficulty in locating a fire that existed above. It is the staff's opinion that the open-lattice ceiling does not constitute a concealed space containing combustible material in accordance with staff guidelines and is, therefore, acceptable. During the plant site audit, the applicant committed to clarify the ceiling arrangement of fire zone Z036 in the FHAR.

Section D.1.i of Appendix A to BTP APCSB 9.5-1 states that floor drains, sized to remove expected fire-fighting waterflow, should be provided in those areas where fixed water fire suppression systems are installed. During the plant site audit, the staff asked the applicant to evaluate the drainage capacity for HVAC charcoal filter units with respect to the maximum flow expected from the fire suppression systems installed within the units.

The applicant stated that the drainage capacity provided from each filter unit is sufficient to remove actual deluge system flow. This is in accordance with the staff guidelines in Section D.1.i of Appendix A to BTP APCSB 9.5-1 and is, therefore, acceptable.

Electrical Cable Construction, Cable Trays, and Cable Penetrations

Section D.3.d of Appendix A to BTP APCSB 9.5-1 states that cable and cable tray penetrations of fire barriers should be sealed to give protection at least equivalent to that of the fire barrier. During the plant site audit, the staff requested information regarding the installation of fire-rated seals for electrical bus ducts which penetrate fire-rated barriers.

The applicant responded that the only electrical bus duct that penetrates a fire barrier is the 15-kV nonsegregated phase bus duct located in the turbine building. This bus duct will have a rated internal fire barrier seal installed per the applicant's Field Change Request BEO-2058. The installation of internal fire-rated seals in electrical bus ducts at fire barriers conforms to staff guidelines and is, therefore, acceptable.

Section D.3.c of Appendix A to BTP APCSB 9.5-1 states that sprinkler systems should be installed to protect cable tray concentrations outside the cable spreading rooms. In the SER, the staff concluded that the applicant had adequately addressed staff concerns about the protection of cable concentrations and that the level of automatic sprinkler protection provided by the applicant for cable concentrations outside the cable spreading rooms was acceptable.

In the SER, the staff stated that the applicant could forego the installation of automatic fire suppression capability in each of nine fire zones (Z007, Z008,

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Z031, Z050, Z058, Z102, Z121, Z138, and Z139) on the basis of cable construction, cable concentrations and configurations, perimeter boundary construction, installed fire protection capabilities, available manual fire-fighting equipment, accessibility for manual fire fighting, and post-fire safe shutdown capabilities. On the basis of its review of the applicant's justifications and fire hazards analyses for these zones, the staff concluded that the installation of automatic sprinkler protection in these nine zones would not significantly increase the level of fire safety. By letter dated March 23, 1987, the applicant stated that automatic fire suppression has been added in all of the above-mentioned zones except Z121. The addition of automatic suppression systems to the above cable concentrations represents an increase in the level of fire protection provided and is, therefore, acceptable.

9.5.1.5 Fire Detection and Suppression

Fire Detection

Section E.1 of Appendix A to BTP APCSB 9.5-1 provides the guidelines for fire detection systems. Detection systems should comply with NFPA 72D, "Standard for the Installation, Maintenance and Use of Proprietary Protective Signalling Systems." NFPA 72D indicates that detector placement should be in accordance with NFPA 72E, which provides guidance on the location and spacing of detectors.

Table 4.2 of the applicant's FHAR states that fire detectors are located in accordance with NFPA 72E-1978. Section 3-5.1.1 of NFPA 72E-1978 states that each bay formed by beams that project more than 18 in. below the ceiling and which are more than 8 feet on center should be treated as a separate area requiring at least one detector.

During the plant site audit, the staff identified several plant areas where the above criterion was not met, such as the cable spreading rooms and the area above the control room ceiling. In general, the ceilings in these areas have bays that are formed by beams projecting more than 18 in. from the ceiling and that are between 7 feet and 8 feet on center. NFPA 72E states that, as a minimum, this configuration have at least a single detector in areas formed by every other beam. During the plant site audit, it was determined that the detectors on the ceilings in these plant areas are installed in bays formed by every third or fourth projecting beam. This configuration does not conform to the applicant's commitment for compliance to NFPA 72E.

By letter dated April 8, 1987 and during the plant site audit, the applicant committed to add detectors to beam pockets throughout the plant before fuel load so that NFPA 72E is met in accordance with the applicant's commitment and staff guidelines. This conforms to Section E.1 of Appendix A to BTP APCSB 9.5-1 and is, therefore, acceptable.

During the plant site audit, the staff requested information regarding the effects of smoke stratification on smoke-detector efficiency as described in NFPA 72E. Smoke stratification occurs when the temperature of the smoke particles generated, usually from a smoldering or small fire, reach the temperature of the surrounding air. Because it has lost the thermal lift, the smoke stops rising and stratifies. Sufficient heat is required to overcome this barrier and carry the smoke particles to the detector. This condition can delay the operation time of smoke detectors installed in an area with high ceilings.

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In a letter dated April 17, 1987, the applicant identified 10 rooms where smoke stratification could occur because of large volumes, ceiling heights of 30 feet or more, and ventilation air rates of less than five air changes per hour during normal plant operating modes.

The ventilation exhaust grilles in these rooms are typically located at either the ceiling or through the wall near the ceiling. This location of return grilles will reduce the probability of smoke stratification adversely affecting detector operation by reducing temperature differences through the room height and causing general air movement to the ceiling.

Where exhaust grilles are not located at the ceiling level of these areas, low quantities of combustible materials exist at the floor level. The combustible materials in these areas are cable trays located above the elevation of the ventilation exhaust grilles. Ionization detectors are located above the trays. The distance between the ceiling detectors and the cable trays installed is not such that stratification would occur. On the basis of the above, the effects of smoke stratification on detector operation time in the rooms identified in the applicant's April 17, 1987 letter are judged to be insignificant.

In the FHAR and letter dated April 17, 1987, the applicant states that detection systems in areas of safety-related buildings comply with the guidelines for Class A systems as defined in NFPA 72D-1975 except for the interconnecting wiring between the local fire panel and the transmitter that transmits the signals to the control room.

NFPA 72E states that Class A detection systems should be capable of operating by providing an alarm signal during a single break or a single ground fault condition. The criterion does not apply to circuits between the alarm signal transmitter and the detector control unit if both are located in adjacent enclosures not more than 3 feet apart and the circuits between the enclosures are routed in conduit. The applicant has stated that non-Class A wiring is used between the transmitter and the control units for a distance in excess of 3 feet.

The panels containing the transmitters and control units and associated conduits that exceed 3 feet of separation are not susceptible to damage during normal plant operations. The transmitters and control units are less than 20 feet apart, but cable runs may be longer. If there is a failure in any circuitry between the transmitter and the control unit, a trouble alarm will be initiated in the control room. The trouble alarm condition will be investigated in accordance with plant procedures. It is the staff's judgment that the non-Class A circuits between the alarm signal transmitters and detector control units in excess of 3 feet are an acceptable deviation from NFPA 72D and Section E.1.a of BTP APCSB 9.5-1.

Water Sprinklers and Hose Standpipe Systems

Section E.3.d of Appendix A to BTP APCSB 9.5-1 states that interior manual hose installations should follow the requirements of NFPA 14. In Table 4.2 of the FHAR, the applicant states that UL-listed or Factory Mutual (FM)-approved non-collapsible hose is installed on manual hose reels where deemed appropriate. During a meeting on March 18, 1987 and in a letter dated April 17, 1987, the

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applicant stated that the noncollapsible hose is not UL listed or FM approved as indicated in the FHAR.

Noncollapsible hose is used wherever the ability to operate a hose stream without removing a complete rack of hose would be advantageous. At the plant site audit, the applicant stated that the noncollapsible hose installed meets or exceeds the working pressure guidelines for UL-listed or FM-approved hose and meets the criteria of NFPA 196, "Standard for Fire Hose." Additionally, all noncollapsible fire hose will be hydrostatically tested in accordance with the applicant's approved fire protection program and replaced with UL-listed hose at the first hose maintenance changeout.

On the basis of the above, the staff concludes that the use of noncollapsible hose that is not UL listed or FM approved does not adversely affect the functional ability of the hose reels and is, therefore, acceptable.

The applicant installed a manually operated, closed-head sprinkler system in each switchgear room (fire zones Z004, Z042, and Z052). Because the array of cable trays and horizontal steel tray supports was similar in arrangement to that of storage racks, the applicant proposed to adopt the criteria in the NFPA standards governing the protection of storage racks (NFPA 231C). In the SER, the staff found that such a design would provide adequate sprinkler coverage for the cable trays and supports, and it was, therefore, acceptable.

By letter dated April 17, 1987, the applicant requested several deviations from the guidelines of NFPA 231C. The deviations requested are from code criteria that are not applicable to the nuclear industry in general or to South Texas in particular and are consistent with staff fire protection guidelines or represent conditions that have been reviewed and approved by the staff in the SER. The identified deviations from NFPA 231C in the letter dated April 17, 1987 are, therefore, acceptable.

Section E.3.c of BTP APCSB 9.5-1 states that automatic sprinkler systems should at a minimum conform to the guidelines of NFPA 13 and NFPA 15. In letters dated October 31 and December 31, 1985, the applicant stated that sprinkler systems provided to protect cable trays may deviate from NFPA criteria.

In the SER, the staff concluded that the deviations identified in the above-referenced letters will not reduce the performance of sprinkler systems and are, therefore, acceptable.

In a letter dated April 17, 1987, the applicant requested additional deviations from the guidelines of NFPA 13. Several of these deviations regard sprinklers on systems protecting cable tray concentrations which had been relocated to avoid obstructions or to optimize spray coverage of cable trays. In these cases, the individual sprinkler spacing criteria of NFPA 13 may not be met. The quantity of sprinklers for the entire protected area will be at least equal to NFPA-recommended quantity.

On the basis of its review of the applicant's letter and observations at the plant site audit, the staff concludes that the deviations from NFPA 13 identified in the applicant's April 17, 1987 letter regarding sprinklers relocated to avoid obstructions or optimize spray coverage of cable trays for systems

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protecting cable tray concentrations are consistent with those approved in the SER and are, therefore, acceptable.

During the plant site audit, the staff observed sprinklers that had not been relocated to avoid obstructions or optimize spray coverage of cable trays located at a distance below the ceiling in excess of NFPA 13 criteria. By letter dated April 8, 1987, the applicant committed to raise all sprinklers that have not been relocated to avoid obstructions to meet NFPA 13 guidelines by fuel load. The resulting sprinkler-head distances from ceilings conform to staff guidelines and are, therefore, acceptable.

The applicant's April 17, 1987 letter identified deviations from the criteria of NFPA 13 for other than sprinkler location. These deviations regarded pipe sway bracing, control valve position, fire department connections, and sprinkler system drainage facilities. The deviations requested are from guidelines that are not applicable to the nuclear industry or will not reduce system performance and are, therefore, acceptable.

Portable Fire Extinguishers

Section E.6 of Appendix A to BTP APCSB 9.5-1 provides staff guidance regarding the installation of portable fire extinguishers. It states that fire extinguishers should be provided in accordance with the guidelines of NFPA 10.

Table 4.2 of the applicant's FHAR states that portable extinguishers, in accordance with NFPA 10-1975, are provided at locations throughout the plant including locations that contain or could present a fire exposure hazard to safety-related equipment.

During the plant site audit, the staff observed that the area located above the control room ceiling (fire area 1) was not provided with a fire extinguisher in accordance with the applicant's commitment to comply with NFPA 10. By letter dated April 8, 1987, the applicant committed to install fire extinguishers at this location by fuel load to meet its commitment. This conforms to Section E.6 of Appendix A to BTP APCSB 9.5-1 and is, therefore, acceptable.

9.5.1.6 Fire Protection for Specific Plant Areas

Containment

In the SER, the staff stated that the applicant had committed to comply with Section III.G.2 of Appendix R to 10 CFR 50 inside the containment where cables and equipment and associated non-safety-related circuits of redundant trains are not separated by a horizontal distance of more than 20 feet with no intervening combustible materials or fire hazards. On the basis of this commitment, the staff concluded that the installation of an areawide fire detection system in the reactor containment building would not significantly increase the level of safety and was an acceptable deviation from Section F.1 of Appendix A to BTP APCSB 9.5-1.

After the SER was issued, in Amendment 3 to the FHAR, the applicant modified its commitment for compliance with the technical requirements of Appendix R inside the containment. Specifically, the applicant proposed and installed a manually actuated, special-hazard water suppression system inside the containment for

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use in separating cables and associated non-safety-related circuits separated by a distance of 20 feet or less.

The staff was concerned that because of the manual nature of the system, the time delay inherent in system activation could lead to fire damage of redundant trains of safe shutdown equipment or circuits.

The applicant responded to the concerns by letter dated April 8, 1987. The applicant justified the installation of the manual water suppression system in lieu of Appendix R, Section III.G criteria on the basis of the open-head, deluge-type sprinklers, procedures requiring system activation from the control room before the fire damaged more than one train of safe shutdown equipment, the detection system provided for the trays, and operator and fire brigade response. The applicant committed to install additional cable tray detection by fuel load to ensure early detection of a fire with the potential for spreading between safety trains.

On the basis of its review of the above-referenced letter and the applicant's commitments, the staff concludes that the omission of an areawide fire detection system remains an acceptable deviation from Section F.1 of Appendix A to BTP APCSB 9.5-1. If further concludes that the applicant has adequately addressed staff concerns regarding the manual fire suppression system separating redundant trains inside the containment and that the level of protection is equivalent to that provided by adherence to Section III.G.2 of Appendix R to 10 CFR 50 and is, therefore, acceptable.

Cable Spreading Rooms

Section F.3(b) of Appendix A to BTP APCSB 9.5-1 states that aisle separation in cable spreading rooms between tray stacks should be at least 3 feet wide and 8 feet nigh. In Table 4.2 of the FHAR, the applicant states that all parts of the cable spreading rooms are accessible for manual fire suppression and can be reached by at least one effective hose stream.

During the plant site audit, the staff reviewed the cable spreading rooms to evaluate available access for manual fire-fighting activities. On the basis of the results of this review, the staff concludes that the aisle separation provided in the cable spreading rooms does not meet staff guidelines. However, access is sufficient to permit effective fire brigade operations as stated in the FHAR.

On the basis of the available access, the staff concludes that the aisle separation provided in the cable spreading rooms is sufficient for effective fire brigade operations and, therefore, is an acceptable deviation from Section F.3(b) of Appendix A to BTP APCSB 9.5-1.

9.5.1.7 Fire Protection of Safe Shutdown Capability

Safe Shutdown Capability

Appendix R to 10 CFR 50 states that fire protection features should be provided for structures, systems, and components important to safe shutdown. These features should limit fire damage so that one train of systems necessary to achieve

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and maintain hot shutdown conditions is free of fire damage. To ensure that one of the redundant trains is free of fire damage, three trains are provided. At South Texas, normally two redundant shutdown trains will be available for safe shutdown of the plant following the occurrence of a fire at any given location as stated in SSER 2.

Section III.J of Appendix R to 10 CFR 50 states that all areas needed for operation of safe shutdown equipment, and in access and egress routes thereto, be provided with emergency lighting units with at least an 8-hour battery power supply.

In Table 4.1 of the FHAR, the applicant committed to provide self-contained emergency lighting with 8-hour minimum battery supply in areas needed for operation of hot standby/hot shutdown equipment and in access and egress routes thereto. In a letter dated March 27, 1987, the applicant requested a deviation from Section III.J to the extent that it requires exterior yard areas to be provided with emergency lighting units.

Operator access routes to various safe shutdown components may require travel outside of buildings. Lighting for these exterior routes is provided by the station's exterior security lighting and portable hand-held lights. During loss of offsite power, the security lighting is powered from the lighting diesel. During the plant site audit, the applicant confirmed that a fire in a safety-related area will not cause the loss of the lighting diesel or exterior lights. Dedicated, controlled, and maintained battery-powered hand-held lights are also provided in the control room for operator use during emergency situations.

On the basis of the above, the staff concludes that the existing security lighting combined with the location and controls of dedicated hand-held lights in the control room provides a level of safety equivalent to the technical requirements of Section III.J of Appendix R and is, therefore, acceptable.

In the March 11, 1987 letter, the applicant requested a deviation from the guidelines of Section D.1.j of Appendix A and Section III.G.2.a of Appendix R to the extent that they require fire area 77 to be separated from fire areas 4, 34, 65, and 67 by a 3-hour-fire-rated barrier. Fire area 77 comprises HVAC and electrical rooms on the roof of the mechanical-electrical auxiliary building. The floor of fire area 77 is above portions of fire areas 4, 34, 65, and 67.

Circuits for the technical support center (TSC) diesel generator are located within fire area 77. The TSC diesel generator and its associated power distribution system provide power to the positive displacement charging pump.

Reactor coolant system (RCS) makeup can be provided from the centrifugal charging pumps (CCPs) powered from trains A and C. The positive displacement charging pump provides the third RCS makeup pathway through the reactor coolant pump seals. Circuits for the train C CCP are located in a tray below fire area 77. The TSC diesel circuits in fire area 77 and train C CCP circuits are not separated by a 3-hour fire barrier because of unrated penetrations.

The unrated penetrations in the floor of fire area 77 are two HVAC penetrations that are not provided with fire dampers. In a letter dated April 8, 1987, the applicant committed to either provide 3-hour-rated fire dampers in these two

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HVAC penetrations or provide a fire-rated barrier for the train C CCP cables by fuel load. On the basis of the above, the staff concludes that the fire protection features proposed comply with the requirements of Appendix R and are, therefore, acceptable. If the train C CCP cables are provided with a rated fire barrier to achieve compliance with Appendix R, the addition of fire dampers in the floor of fire area 77 will not significantly increase the level of fire protection. Therefore, if the CCP cables are protected, the lack of fire dampers in the floor of fire area 77 represents an acceptable deviation from Section D.1.j of Appendix A to BTP APCSB 9.5-1.

Fire area 63 includes the entire interior of the containment building. It is separated from other fire areas by the containment exterior wall. In a letter dated March 11, 1987 and in the FHAR, the applicant stated that the containment access hatch and airlocks are not fire rated.

The airlocks and hatch were observed during the plant site audit to be similar to airlocks used at other facilities and were designed to meet design-basis accident criteria. The combustible loading nearby is low; therefore, a fire of significant magnitude or duration should not occur near the airlocks or hatch. If a fire does occur, it is probable that the substantial construction of the airlocks and hatch will prevent fire propagation through the containment boundary. The staff, therefore, concludes that the unrated containment access hatch and airlocks are acceptable deviations from Section III.G of Appendix R to 10 CFR 50 and Section D.1.j of Appendix A to BTP APCSB 9.5-1.

In letters dated March 27 and April 17, 1987, the applicant identified the following six fire areas which do not have full area suppression in accordance with Section III.G of Appendix R: fire areas 3, 27, 2, 67, 32, and 4. Circuits required to achieve safe shutdown in the event of a fire in these areas are protected with fire-rated barriers. These barriers consist of cable wraps rated in hours of fire resistance.

Where no automatic fire suppression is provided in the area of the circuits protected by cable fire barriers, the cable fire barrier has a fire rating of 3 hours. Where an automatic fire suppression system is installed within the area and provides protective coverage for the raceway containing the required safe shutdown circuit, the fire rating of the cable fire barrier is 1 hour.

Where the interface between the 3-hour- and 1-hour-fire-rated circuit wrapping is within the fire area, the 3-hour wrap extends at least 5 feet into the area protected with automatic suppression. Areawide fire detection is provided throughout each fire area.

The fire protection features protecting safe shutdown circuits in the above fire areas meet the criteria of Section III.G of Appendix R to 10 CFR 50, since fire barriers with a 3-hour rating are provided in areas without fire suppression; 1-hour in areas with fire suppression. The minimum 5-foot transition between 3-hour and 1-hour protective wrap ensures that the transition is adequately protected.

On the basis of the above, the staff conclude that the lack of full area suppression in fire areas 3, 27, 2, 67, 32, and 4 does not adversely affect the protection of safe shutdown equipment and is, therefore, acceptable.

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9.5.1.8 Conclusions

Summary of Approved Deviations From NRC Fire Protection Guidelines

In the SER, the staff listed 13 deviations from Appendix A to BTP APCSB 9.5-1 and Appendix R to 10 CFR 50. On the basis of the evaluations in this supplement, the staff concludes that the following additional deviations are acceptable as described above:

(1) exterior fire area boundaries
(2) fire dampers FF-036, FF-367, and FF-368
(3) sluice trough in essential cooling water pump areas
(4) fire door clearance gaps
(5) horizontal fire doors
(6) security modifications to fire doors
(7) removable block wall sections
(8) combustible materials within concealed spaces
(9) exterior emergency lighting
(10) deviation from NFPA 720
(11) deviations from NFPA 231C
(12) deviations from NFPA 13
(13) containment--separation of circuits and equipment
(14) cable spreading room--aisle separation

9.5.3 Lighting Systems

In the SER, the staff stated that the dc emergency lighting system inservice inspection and testing program would include the following:

(1) At least once every 12 months, the installed emergency dc lighting packs shall be verified as operable and shown to provide rated illumination and the battery leads and wiring connections shall be inspected as recommended by the manufacturer.

(2) At 5-year intervals, a representative sample of batteries will be load tested or replaced as necessary.

By letters dated May 27, September 30, and December 9, 1986 and January 30, 1987, the applicant stated that it does not intend to perform an annual rated illumination check of the dc emergency lighting system but rather an annual pushbutton light operability check. It is the staff's position that the operability check will not adequately demonstrate functionality of the dc emergency lighting system. The status of this item was changed to that of an open item (No. 20).

In a phone conversation between the staff and the applicant on April 8, 1987, the applicant agreed to the above inservice and testing program with the following clarification as to what constitutes the rated illumination check:

(1) During preservice or preoperational testing of the dc lighting system, illumination levels at work stations (minimum 10 foot-candles) and on access and egress paths (minimum 2 to 5 foot-candles) will be verified,

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both with normal lighting off and with ambient lighting. This will become the plant baseline for illumination levels for dc lighting.

(2) The applicant will check, on a yearly basis, the illumination level at each light with or without ambient lighting.

(3) The applicant will identify appropriate criteria for taking corrective actions to ensure that adequate illumination is maintained.

Therefore, the staff finds the dc lighting inservice inspection program acceptable. This confirmation was received by letter dated April 28, 1987, and, therefore, Open Item 20 is closed.

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13 CONDUCT OF OPERATIONS

13.1 Organizational Structure of Applicant

In the SER, the staff identified confirmatory items that would be resolved through examination of station procedures and through interviews with corporate-level and station management personnel shortly before fuel load. During March 3-5, 1987, the staff examined the procedures and conducted the interviews at the site. This safety evaluation is based on the findings of that site visit and on documents submitted as a result of that visit.

13.1.1 Management and Technical Support Organization

13.1.1.2 Organizational Arrangements

In the SER, the staff stated that the effectiveness of the relationship between offsite support groups and the plant staff was an open item. Construction of the first unit is nearing completion. Accordingly, the utility management structure has been evolving as responsibility for various systems and components is transferred to the operating staff. This transition will progress through three identifiable steps. Figure 13.1 shows the organizational structure as it existed at the time of the staff visit, and Figure 13.2 shows the organization from April 1, 1987 through the start of commercial operation of Unit 1. Figure 13.3 shows the organization as it will appear from the start of commercial operation of Unit 1 through the completion of Unit 2, and Figure 13.4 as it is planned following completion of Unit 2.

The principal change that occurred in April was an acknowledgement that the responsibilities of the Vice President, Operations, for bringing the unit on line will be increasing while those of the Vice President, Engineering and Construction, will be diminishing. The responsibility for engineering assurance will transfer from the Vice President, Engineering and Construction, and a Unit 1 operation support group will be created. This support group, however, will remain under the management of the South Texas Project office during this interim period.

The major evolutionary step that will occur in the organization after Unit 1 starts commercial operation will be the separation of Unit 1 support from the South Texas Project. At that time Unit 1 operating support will come directly through the Vice President, Engineering and Construction.

The transition from construction to operation appears to be planned in a logical and workable manner, and the proposed organizational concepts are acceptable.

The staff reviewed the qualifications of key management personnel and interviewed the following individuals to better understand the working relationship between the operating and support groups.

- T. Bowman - Shift Technical Advisor
- K. K. Chitkara

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- D. J. Cody
- J. E. Geiger
- J. H. Goldberg
- G. L. Jarvela
- H. Johnson - Shift Supervisor
- W. H. Kinsey
- J. Loesch
- M. Ludwig
- M. A. McBurnett
- G. L. Parkey
- M. A. Robinson
- T. Templeman - Unit Operations Supervisor

The staff finds that there is a clear understanding of the organization, interactions, and schedule for bringing the unit into service, and that the mechanism for coordination between the operating staff and the support personnel is adequate. The staff finds that the management and technical support organization of the applicant is adequate and conforms with SRP Section 13.1.1. Confirmatory Item 23 is therefore closed.

13.1.2 Operating Organization

13.1.2.1 Plant Organization

The availability of qualified operators to satisfy the guidelines of Generic Letter 84-16 was left open in the SER. By letter dated February 11, 1987, the applicant advised the staff that it expects to have a total of 60 persons complete license training before the operating license is issued. In a letter dated March 13, 1987, the applicant identified six licensed senior reactor operators who meet the guidelines of the generic letter for operating experience and who will serve as shift supervisors for Unit 1.

On the basis of the current availability of these individuals and a review of the operating experience history, the staff finds that the applicant will have a sufficient number of experienced operators to meet the guidelines of Generic Letter 84-16. Confirmatory Item 24 is therefore closed.

13.3 Emergency Planning

13.3.1 Introduction

On April 21, 1987, the applicant (or utility) filed Revision 3 of the South Texas Project Electric Generating Station Emergency Plan with the NRC. Previously, the staff had reviewed and commented on earlier versions of the emergency plan. The emergency plan applies to the applicants Station Emergency Response Organization and is supported by emergency plan implementing procedures (EPIPs).

The acceptance criteria used as the basis for the staff's review of the South Texas emergency plan are specified in SRP Section 13.3, "Emergency Planning" (NUREG-0800) and include the planning standards of 10 CFR 50.47(b), the requirements of Appendix E to 10 CFR 50, and the specific guidance criteria of NUREG-0654/FEMA-REP-1, Revision 1, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," dated November 1980. The criteria of NUREG-0654 have been

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endorsed in Regulatory Guide 1.101, Revision 2, "Emergency Planning and Preparedness for Nuclear Power Reactors," dated October 1981, and thus have the same status as a regulatory guide.

Evaluation of the adequacy of emergency preparedness for the South Texas facility also involves the review of State and local radiological emergency response plans and preparedness by the Federal Emergency Agency (FEMA). The findings and determinations of FEMA on the adequacy of the State and local emergency response plans for South Texas will be presented in a future supplement to the SER. An overall finding of adequacy for onsite and offsite emergency preparedness is required before a license authorizing operations above 5% of rated power may be issued.

Section 13.3.2 of this report lists each planning standard of 10 CFR 50.47(b) followed by an evaluation of the applicable portions of the plan that relate principally to that particular standard. Section 13.3.3 of this report provides the staff's conclusions.

13.3.2 Evaluation of the Emergency Plan

13.3.2.1 Assignment of Responsibility (Organizational Control)

Planning Standard

> Primary responsibilities for emergency response by the nuclear facility licensee, and by State and local organizations within the Emergency Planning Zones have been assigned, the emergency responsibilities of the various supporting organizations have been specifically established, and each principal response organization has staff to respond and to augment its initial response on a continuous basis.

Emergency Plan Evaluation

The emergency plan identifies the Federal, State, and local organizations that are intended to be part of the overall response organization for the South Texas Project site plume exposure pathway emergency planning zone (EPZ) and the ingestion exposure pathway EPZ. The plume exposure pathway EPZ is located entirely within Matagorda County, and the ingestion exposure pathway EPZ lies completely within the State of Texas. The largest population concentrations are located outside the plume exposure pathway EPZ in Bay City and the City of Palacios, approximately 14 miles and 12 miles from the site, respectively. In the event of an emergency, utility personnel will be in close contact with the chief executives of Matagorda County, Bay City, and the City of Palacios, as well as officials of the State of Texas Bureau of Radiation Control (BRC), the State of Texas Department of Public Safety, Division of Emergency Management (DEM), and the NRC. The State BRC is responsible for the coordination with other State and Federal agencies.

The emergency plan describes the operational roles and responsibilities of the utility, State, and local organizations that are part of the emergency response organization. A block diagram in the plan illustrates the interrelationships among these organizations, and the specific individual within these organizations who shall be in charge of emergency response is listed by title. Details

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concerning the respective organizational responsibilities, functions to be performed, and procedures for utilizing personnel and equipment resources are provided in the utility, State, and local radiological emergency response plans.

In the event of a radiological emergency at South Texas Project, the utility has the responsibility to recognize and classify an emergency condition, notify offsite authorities, maintain communications with response groups, assess the status of the accident, take protective measures on site, and recommend protective actions to offsite authorities. Initially, the Shift Supervisor is designated as the Emergency Director of the Onshift Response Organization and has the authority for implementing the utility's responsibilities. A shift supervisor is on site 24 hours a day, thereby ensuring 24-hour-per-day emergency response, including notification functions. The Shift Supervisor will be relieved by the duty Emergency Director who is responsible for the overall coordination of the Station Emergency Response Organization.

Written agreements referring to the concept of operations developed with outside agencies and other support organizations having an emergency response role are contained in an attachment to the plan. Each letter of agreement identifies the assistance to be provided and general implementation criteria.

The South Texas Project emergency response organization as well as the principal supporting organizations are structured to provide for continuous (24-hour) operations for a protracted period. The Emergency Director through the General Services Director is responsible for ensuring that technical, administrative, and material resources are available at the site on a continuous basis.

13.3.2.2 Onsite Emergency Organization

Planning Standard

> Onshift facility licensee responsibilities for emergency response are unambiguously defined, adequate staffing to provide initial facility accident response in key functional areas is maintained at all times, timely augmentation of response capabilities is available, and the interfaces among various onsite response activities and offsite support and response activities are specified.

Emergency Plan Evaluation

The onsite emergency organization of plant staff personnel is specified in the plan. The relation between the responsibilities and duties of the Station Emergency Response Organization and those of the normal staff complement is delineated in Table C-3 and described in Section C of the plan. The Shift Supervisor initially will assume command of the Onshift Response Organization as the Emergency Director. In the position of Emergency Director, the Shift Supervisor has the same authority, responsibilities, and actions that cannot be delegated as those specified for the Emergency Director of the Station Emergency Response Organization. The Shift Supervisor will be relieved by the duty Emergency Director when the Station Emergency Response Organization is activated at the alert level. The functional responsibilities assigned to the Emergency Director are specified in the plan, including those that may not be delegated. In particular, the Emergency Director has the responsibility to make decisions

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about notifying offsite authorities and to approve protective action recommendations to offsite authorities.

The positions or titles and major responsibilities to be performed are specified for each functional area of emergency activity. The Station Emergency Response Organization consists both of onshift and duty positions. It will be activated at the alert, site area, or general emergency level and will be staffed immediately by onshift personnel. The onshift personnel are augmented by duty station personnel.

The plan describes the interfaces between and among the station functional areas of emergency activity. The plan further illustrates these interfaces in a block diagram, including the locations where the emergency activities will take place. Corporate public affairs personnel who will augment the site staff are specified. Offsite support organizations including police, fire, ambulance, and medical are specified in Section A.2 of the plan, and the interfaces with the onsite emergency organization are identified. Technical support is available from Bechtel Energy Corporation, Westinghouse Electric Corporation, and the Institute of Nuclear Power Operations (INPO). Copies of letters of agreement with the support organizations are attached to the plan.

The applicant's Onshift Response Organization shown in Table C-2 of the plan generally conforms to the minimum staffing guidance for emergencies that is contained in Table 2 of Supplement 1 to NUREG-0737 (also Table B-1 of NUREG-0654). The applicant's staffing plan designates two radiation protection technicians on shift with eight additional radiation protection technicians available within 45 minutes. The guidance specifies two radiation protection technicians on shift and six within 30 minutes. When Unit 2 is operational, two additional radiation protection technicians will be available on shift.

The shift technical advisors at South Texas Project are nuclear engineers. The core/thermal hydraulics expertise that NUREG-0654 recommends be available within 30 minutes is on shift in the position of the shift technical advisor. An additional nuclear engineer will augment the onshift organization within 30 to 60 minutes. The staff finds the applicant's shift staffing and augmentation goals for emergencies to be satisfactory.

13.3.2.3 Emergency Response Support and Resources

Planning Standard

> Arrangements for requesting and effectively using assistance resources have been made, arrangements to accommodate State and local staff at the licensee's near-site Emergency Operations Facility have been made, and other organizations capable of augmenting the planned response have been identified.

Emergency Plan Evaluation

Federal assistance is available through the State of Texas Bureau of Radiation Control. The Emergency Director is authorized to request Federal assistance on behalf of the station. The U.S. Coast Guard will provide assistance through the Matagorda County Sheriff's Office. A letter of agreement with the Coast

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Guard station is in place for vessel traffic control on the Colorado River and other navigable waters.

Office space and telephone lines have been made available within the onsite emergency response facilities for the Federal agencies, specifically the NRC and FEMA, who would be dispatched to the site as part of the Federal response. NRC office space is available within the applicant's emergency operations center (EOC), the technical support center (TSC), and control room. FEMA office space is available in thee EOC. Operational office space is also maintained in the EOC for representatives of the State of Texas and Matagorda County.

At the request of the appropriate State or county authorities, utility representatives will be dispatched to the State of Texas Emergency Operations Center in Austin and the Matagorda County EOC in Bay City. Station spokespersons and support personnel will staff the media information center.

The emergency plan identifies the commercial organizations available to provide assistance in an emergency in addition to the local service support organizations. Houston Lighting and Power Company laboratories can be supplemented by a mobile laboratory operated by the State of Texas Bureau of Radiation Control and the laboratory facilities of other nuclear facilities as coordinated by INPO. Letters of agreement describing these arrangements are contained in Attachment 3 to the plan.

13.3.2.4 Emergency Classification System

Planning Standard

A standard emergency classification and action level scheme, the bases of which include facility system and effluent parameters, is in use by the nuclear facility licensee, and State and local response plans call for reliance on information provided by facility licensees for determinations of minimum initial offsite response measures.

Emergency Plan Evaluation

The applicant has established a standard emergency classification scheme based on facility system and effluent parameters. Accidents or emergency situations have been categorized into the four standard NUREG-0654 emergency classes: notification of unusual event, alert, site area emergency, and general emergency. Each of the four emergency classes has characteristic emergency action levels (EALs). The EALs which determine the emergency class are based on the actual or potential failure, malfunction, or improper operation of plant structures, systems, and components. The initiating conditions consist of physically observable events, process and radiation monitoring instrumentation, equipment status, and radiochemical analyses. The process and radiation monitoring instrumentation and radiochemical analyses are used to determine if a barrier designed to contain radioactive material has failed and/or if radioactive effluents released to the environment are within established values.

The plant symptoms or conditions, the corresponding EALs, and the emergency classification are given in Tables D-1 and D-2 of the emergency plan and in implementing procedure EPIP OEPP01-ZA-0001.

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The EALs used for the classification of emergencies have been accepted by the State of Texas and Matagorda County Emergency Management agencies and will be reviewed on an annual basis. The staff has reviewed and commented on the EALs. The applicant has considered each of the staff's comments and revised the EALs as appropriate.

13.3.2.5 Notification Methods and procedures

Planning Standard

> Procedures have been established for notification, by the licensee of State and local response organizations and for notification of emergency personnel by all response organizations; the content of initial and followup messages to response organizations and the public has been established; and means to provide early notification and clear instruction to the populace within the plume exposure pathway Emergency Planning Zone have been established.

Emergency Plan Evaluation

The emergency plans will be activated with the identification and classification of an emergency based on the standard emergency classification and action level scheme. The Shift Supervisor will assume initial command of the Onshift Response Organization as the Emergency Director. The notification of response organizations is based on the response criteria developed for each emergency classification. The Onshift Response Organization will be activated by the public address system and/or the evacuation alarm system. The duty emergency response organization will be notified by pocket pager.

Direct telephone lines will be utilized to notify the responsible State agencies and local officials within the plume exposure pathway EPZ within 15 minutes after the declaration of an emergency. The principal onsite points of contact are the State Department of Public Safety Disaster District Sub 2A Office in Pierce, Texas and the Matagorda County Sheriff's Office in Bay City. Following notification, the State Disaster District will call back to the station to authenticate messages. The plan describes the State and local contacts, the notification method, and the means for verifying messages. Predetermined message formats for notification of offsite agencies are contained in EPIP OEPP01-ZA-003, "Emergency Offsite Notifications," the Texas Emergency Management Plan, and the Matagorda County Emergency Management Plan.

The utility, in conjunction with the State of Texas and the local communities, has established the message form to allow information pertinent to the emergency classification to be supplied. This information includes the emergency classification, details of the onsite situation, radiological release data including meteorological parameters, and protective action recommendations. Additional technical information will be provided initially to State and county authorities via telephone. To facilitate these communications, representatives from the State and county organizations will respond to the station EOC and coordinate data with utility response personnel once the response centers are activated.

State and local officials will utilize the prompt notification system to notify the public in the appropriate areas as to what protective action should be taken.

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The State and local officials have the capability to make a public notification decision promptly and to complete the initial notification of the public within the plume exposure pathway EPZ within about 15 minutes after being informed by the utility of an emergency condition. The prompt notification system consists of tone alert radios located in residences and establishments and preset to the emergency broadcast system (EBS) frequency supplemented by 11 outdoor warning sirens in the more densely populated areas. The tone alert radios are activated by an EBS signal, which produces a full-volume alerting tone. The sirens are activated by the Matagorda County Emergency Director from the Sheriff's Office. Following the alerting tone, emergency instructions will be provided by the radio station. The content of prescribed EBS messages is contained in the county emergency response plan. The administrative procedures for notifying and providing prompt instructions to the public within the plume exposure pathway EPZ are contained in the county emergency plan.

The sirens have been installed, and the tone alert radios will be distributed. NRC Region IV personnel will verify that the prompt notification system is operational before fuel load.

13.3.2.6 Emergency Communications

Planning Standard

> Provisions exist for prompt communications among principal response organizations to emergency personnel and to the public.

Emergency Plan Evaluation

The communication plan for emergencies includes reliable primary and backup means of communication. The plan contains the department titles for notification of response organizations. The State and county links used for initial notification will be manned 24 hours a day. The direct telephone lines used for initial notification will be used throughout the event; however, once the offsite and onsite emergency response centers are activated, they may be augmented by commercial telephones and the Houston Lighting and Power Company two-way radio system.

Communication among the station emergency response facilities consists of a combination of commercial and station telephones, telecopiers, public address system, emergency response facilities data acquisition and display system (ERFDADS), and two-way radios. A computerized branch exchange telephone system provides the basic means of communication with the station facilities. The station system uses commercial lines and a corporate microwave system to Bay City and Houston. Direct telephone lines exist from the control room, TSC, and EOC to the State of Texas Department of Public Safety, Disaster District Sub 2A Office in Pierce and the Matagorda County Sheriff's Office.

Fully redundant radio repeater base stations, with automatic rollover, provide communications between control base stations, mobile units, and hand-held portable radios within the plant area. The station radio system includes base units in the control room, TSC, EOC, site access facility (SAF), central alarm station, and secondary alarm station with separate normal and backup power supplies. Pocket paging transmitters, accessed by station telephone, provide tone, voice

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digital readout codes, and vibration features for contacting response organization personnel.

Ambulances are equipped with radios and can communicate with the local hospitals. Communication between the station and the fixed and mobile medical facilities will be by a two-way radio link through the Matagorda County EOC using the Matagorda County Sheriff's Office frequency.

The station has an NRC health physics network, which consists of a telephone line to the NRC from the radiation protection office in the mechanical auxiliary building and the EOC and an emergency notification system to the NRC from the control room, TSC, and EOC. Backup power is available for this system.

Monthly tests will be conducted on all the communication systems used to notify station, State, and local emergency response personnel and agencies. Communication systems among all emergency response facilities and organizations, including offsite monitoring teams, also will be tested during drills and the annual exercise.

13.3.2.7 Public Education and Information

Planning Standard

> Information is made available to the public on a periodic basis on how they will be notified and what their initial actions should be in an emergency (e.g., listening to a local broadcast station and remaining indoors), the principal points of contact with the news media for dissemination of information during an emergency (including the physical location or locations) are established in advance, and procedures for coordinated dissemination of information to the public are established.

Emergency Plan Evaluation

Information in the form of printed materials dealing with nuclear emergencies will be disseminated annually to all residents within the 10-mile EPZ. The mailouts contain information on protective actions and educational information on radiation. The mailouts also contain specific local information such as evacuation routes, maps, EBS stations, telephone numbers for additional information, and mail-in cards requesting assistance for individuals with special needs. This information will be made available to transients at appropriate locations in public areas within the plume exposure pathway EPZ. The public information is printed in English and Spanish to inform all residents of the area. The applicant has established a rumor control program that will be activated during a declared emergency.

The Corporate Public Affairs Department develops programs addressing various aspects of nuclear power including emergency planning. An information program to be conducted annually will acquaint the news media with the emergency planning effort at the station, information concerning radiation, and points of contact for release of information in an emergency.

During an emergency the media information center will be staffed by station and Houston Lighting and Power Company, State, county, and Federal public

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information personnel who provide the principal media contacts. The media information center is located at the Bay City Holiday Inn in Bay City, Texas. The company spokesperson position will be filled by an emergency response organization duty roster designee who will act as the official company spokesperson.

The Emergency Director will approve information to be transmitted from the EOC to the media information center. The Media Information Director will obtain information from the Site Public Affairs Manager who will be located at the EOC. News releases will be developed and then coordinated with Federal, State, and local public information officers. The Media Information Director will disseminate news releases to the news media and other interested parties at the media information center. This responsibility cannot be delegated.

13.3.2.8 Emergency Facilities and Equipment

Planning Standard

Adequate emergency facilities and equipment to support the emergency response are provided and maintained.

Emergency Plan Evaluation

The TSC is the emergency operations work area for management, engineering, and technical personnel who will provide support to plant operations personnel in the control room, operations support center (OSC), and EOC during an emergency. A separate TSC is provided for each unit. The TSC is located on the 72-foot elevation of the mechanical-electrical auxiliary building. The TSC is equipped with a heating, ventilation, and air conditioning system that can be isolated under adverse conditions. The TSC will be activated for an alert or higher level of emergency and can be fully activated within approximately 1 hour. The TSC will serve as the EOC if the EOC cannot be activated at approximately the same time. Provisions have been made for the receipt and display of plant system data as well as for the permanent storage of records and design drawings necessary to support the functions of the TSC during emergency conditions.

The OSC is an onsite facility where station emergency response support personnel will assemble in an emergency. The OSC for the station is located in the classroom section of the administration building east of Unit 1. Personnel reporting to the OSC will make up the plant emergency response teams. The OSC is activated on declaration of an alert or higher level emergency. Emergency supplies in the OSC include radiological monitoring equipment, portable two-way radios, protective clothing, and respirators. In addition, normal station radiological protection and maintenance equipment is accessible to the OSC.

Houston Lighting and Power Company has elected to designate its emergency operations facility as the EOC. The EOC provides an area for the overall management of emergency response activities including the coordination of radiological and environmental assessments and determination of recommended public protective actions. The EOC is located approximately 1/2 mile east of Unit 1 adjacent and connected to the nuclear training facility. The EOC has been designed to be habitable under postulated accident conditions. The design includes a ventilation system with high efficiency particulate air filters. The EOC is activated at an alert or higher level emergency class. Office space has been allocated

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in the EOC for liaison personnel from Matagorda County, the State of Texas, NRC, and FEMA. Communications, plant assessment, and monitoring equipment as well as necessary records and drawings are provided in the EOC. The utility has established a backup emergency operations facility (designated as its alternate EOC) that is located approximately 14 miles from the station in the utility's Bay City Service Center.

On the basis of a review of the information in the emergency plan and procedures, and the findings of the emergency plan implementation appraisal at the South Texas Project site on December 1-12, 1986 (see Inspection Report 50-498/499/86-35 dated February 26, 1987), the staff concludes that, on an interim basis, the South Texas Project emergency response facilities (ERFs) are adequate to support a response effort in the event of an emergency. The completion of the installation and testing of certain systems and equipment, as noted in the inspection report, will be verified in a subsequent inspection before fuel load. As indicated in Supplement 1 to NUREG-0737, the staff will conduct a postimplementation appraisal of the applicant's completed ERFs on a schedule to be developed between the applicant and the NRC.

The emergency plan specifies the onsite monitoring systems and equipment to be used to initiate emergency measures and assess emergency conditions including meteorological instrumentation, seismic monitors, radiological process monitors, area radiation monitors, portable monitors and sampling equipment, nonradiological process monitors, and fire and combustion products detectors. Additional geophysical monitoring information is available from offsite sources.

The plan describes the offsite radiological environmental monitoring program, which includes thermoluminescent dosimeters for direct radiation measurements, airborne particulate and iodine continuous samplers, and sampling to evaluate possible long-term exposures from ground deposition and various food chain pathways in the vicinity of the plant. Radiation monitoring team kits contain air monitoring equipment, sampling equipment, protective clothing, and respiratory protection. The Radiological Director at the EOC will analyze field monitoring data and coordinate sample media.

Laboratory facilities to analyze the environmental samples include the radiological and radiochemistry laboratories in both units at the station and in the Houston Lighting and Power Company Energy Development Center in Houston, Texas. In addition, laboratory services will be available at other nuclear facilities as coordinated by INPO and from a mobile radiological laboratory operated by the State of Texas Bureau of Radiation Control.

Emergency equipment and supplies will be inventoried, inspected, and operationally checked on a periodic basis. Items that fail inspection will be replaced from reserve equipment and will be repaired or calibrated as necessary. Table G-1 of the plan identifies emergency kits and their locations. A general list of equipment contained in each kit is included in the plan.

The emergency plan describes the meteorological program for emergencies. Meteorological parameters collected on site include wind speed and direction at the 10-meter and 60-meter levels of the 60-meter primary tower. Vertical temperature differences are determined between elevations to provide a measure of atmospheric stability. A secondary 10-meter tower supports backup instrumentation to measure air temperature, wind speed, and wind direction. The measurements are

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available in the control room, the TSC, and the EOC. This information is also available to the NRC and State and county authorities via telephone modem or voice. Weather forecasts are available from the National Weather Service facilities in Alvin, Victoria, and Galveston, Texas.

The applicant's meteorological measurements program was discussed in SER Section 2.3.3. The staff concluded that the meteorological measurements program has an emergency response capability in accordance with NUREG-0654/FEMA-REP-1 and Supplement 1 to NUREG-0737. The meteorological program and dose assessment models will be further evaluated as part of the postimplementation appraisal of the South Texas Project emergency response facilities in accordance with Supplement 1 to NUREG-0737.

13.3.2.9 Accident Assessment

Planning Standard

> Adequate methods, systems and equipment for assessing and monitoring actual or potential offsite consequences of a radiological condition are in use.

Emergency Plan Evaluation

The plan identifies specific instrument readings and other observable and measurable parameters that, if exceeded, will initiate the declaration of an emergency in accordance with the applicant's emergency classification and action level scheme. South Texas Project has varied and extensive systems for monitoring the actual or potential release of radioactive materials to the environment. These include radiation area and process/effluent stream monitors and a postaccident sampling system. Meteorological parameters are available from ERFDADS and the control room meteorological instrumentation.

Before the augmentation of the Station Emergency Response Organization and activation of the emergency response facilities, the classification of an event by the Shift Supervisor is based on plant conditions as reflected by instrument readings in the control room and the corresponding emergency action levels (EALs). The Onshift Response Organization will have the complete capability to perform the detection, classification, and notification functions in the early phases of an emergency, including dose assessment and development of offsite protective action recommendations. Within 30 minutes of the declaration of an emergency, a monitoring program will be established to assess potential releases or the extent of an actual release and to provide guidance for appropriate protective measures.

Environmental radiological impact analysis is available on the radiation monitoring system RM-21A computer and via the emergency response facilities data acquisition and display system. The RM-21A computer calculates dose assessments in two modes using Class A model software. The emergency response mode allows control room staff to obtain real-time assessments of accident conditions. A minimum of operator action is required in this mode. The accident analysis mode allows staff in the control room and other emergency response facilities to review a release and analyze its consequences in detail. Radiation effluent data, vent flowrate data, and meteorological data obtained from station monitoring instrumentation are stored in the RM-21A data base. Each of these

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parameters is sampled every 5 seconds, and the previous 15 minutes of data samples are averaged at 1-minute and 15-minute intervals.

The isotopic composition is obtained from one of four options provided in the software model. The user can use data obtained automatically from actual sample results via the counting equipment data link, obtain isotopic-mix estimates from a file of mix estimates for 10 postulated accidents, manually enter an estimate of sample results data for each effluent channel when and if the data become available, and bypass the sample results data requirement by manually entering release values directly.

Atmospheric dispersion (χ/Q) values are generated by another program from either the most recent average 1-minute or 15-minute meteorological data which are obtained automatically from the data base. The model uses a centerline Gaussian dispersion model corrected for site-specific features such as terrain effects, source geometry, and source location. If the meteorological data are unavailable from the meteorological digital processors, manual input of this information is available.

Data in the 1-minute or 15-minute radiation effluent data file and appropriate decay factors are used with one of the four isotopic composition options to generate a release value (Q) for each isotope. Radiation dose is computed by using the χ/Q value and the Q value. Maximum individual doses at 20 locations for each sector out to 50 miles are calculated. The RM-21A system calculates whole-body dose and skin dose from plume immersion, whole-body dose from an overhead cloud, thyroid dose from iodine inhalation, thyroid dose from milk ingestion, and whole-body dose from contaminated ground deposition. Integrated doses are obtained from actual individual doses for a user specified time period.

If the RM-21A computer-based dose calculation method is not available, two other dose calculation methods can be utilized. A modified interactive dose assessment model can be used for performing offsite dose projections on a personal computer. This program is used to calculate whole-body and inhalation thyroid dose and dose rates. A manual method, using dose rate tables, is a third available method. The tables predict whole-body and child thyroid doses at distances from 1 to 10 miles from the plant based on atmospheric class and on estimated release rate.

The applicant has established the capability and resources for field monitoring within the plume exposure pathway EPZ. Specific procedures have been developed for activating, equipping, transporting, and communicating with the radiological emergency monitoring teams. These teams are trained to collect air samples and survey data to assist in rapidly defining the affected areas and assess the extent and significance of the release. Field monitoring teams can be deployed within 30 minutes of the declaration of an emergency. Instrumentation available for the teams will have the capability to detect and measure radioiodine concentrations in air to a minimum detectable activity of at least 10^{-7} μCi/cc under field conditions.

The applicant's capability to implement the dose assessment methodology was examined during the onsite appraisal conducted at South Texas Project on December 1-12, 1986. Several open items, identified during the appraisal, will be resolved by the NRC staff during followup inspections before fuel loading. In addition, the applicant's dose assessment program will be evaluated further

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as part of the postimplementation appraisal of the emergency response facilities in accordance with Supplement 1 to NUREG-0737.

13.3.2.10 Protective Response

Planning Standard

> A range of protective actions has been developed for the plume exposure pathway EPZ for emergency workers and the public. Guidelines for the choice of protective actions during an emergency, consistent with Federal guidance, are developed and in place, and protective actions for the ingestion exposure pathway EPZ appropriate to the locale have been developed.

Emergency Plan Evaluation

The protective response actions for onsite personnel including station personnel, contractors, vendors, construction personnel, and visitors are described in the plan. The actuation of alarms and announcements over the station public address system will be used to ensure that all personnel within the protected area are notified and advised of an emergency situation. Persons within the owner-controlled area will be notified through the station public address system and by route alerting around the reservoir by security personnel.

A specific procedure has been developed to evacuate the site in the event of a site area or general emergency, and evacuation routes and assembly areas have been established. Provisions have been made to monitor evacuees at the east gate house and the EOC and, if necessary, decontaminate personnel at the EOC. Personnel can be evacuated to the assembly areas within about 30 minutes. Additional onsite protective measures for individual emergency workers include the use of respiratory protection equipment, dosimetry, and protective clothing.

The plan describes the applicant's decisionmaking process for recommending protective actions to State and local authorities. The event will be classified on the basis of EALs according to the emergency classification scheme. The initiating conditions consist of observable events, instrument readings, radiochemical analysis, and dose projections. The utility will develop protective action recommendations and report them to the responsible State agencies and to the local decisionmaking officials within the plume exposure pathway EPZ using the dedicated communication link or commercial telephone lines. Responsible State agencies to be notified include the State of Texes Bureau of Radiation Control and the State Department of Public Safety, Division of Emergency Management. Matagorda County will be similarly notified. The county operates on the duty-officer concept, which ensures that a decisionmaker will be available at all times.

Recommendations for protective actions for the general public are based on plant conditions and on data derived from offsite dose assessment or actual field monitoring measurements. The applicant has developed a flowchart to facilitate the development of protective action recommendations. The protective action recommendations are consistent with the U.S. Environmental Protection Agency's protective action guide for doses to individuals.

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The emergency classification scheme has built-in prescribed protective actions for the public that State and local officials can initiate. These protective actions, as shown in Table I-2 of the plan, include shelter and access control for a 2-mile radius and 10 miles downwind and evacuation for a 2-mile radius and 10 miles downwind. Since protective actions are prescribed for each classification, State and local authorities can make prompt decisions in fast-moving events. In slower-moving events, with the State, local, and utility emergency response facilities fully activated, State and local authorities can make protective action decisions based on more definitive recommendations from the utility. The actual decision to implement a protective action rests with the County Emergency Director. The County Emergency Director will direct the emergency broadcast system radio station to activate the prompt notification system to advise the public to take the protective action.

Evacuation time estimates (ETEs) for the plume exposure EPZ are contained in Attachment 4 to the station plan. The ETE study includes information on resident and transient population distribution, evacuation routes, and road characteristics and capacity. ETEs are developed for subareas within the plume exposure pathway EPZ and for the entire EPZ for both normal and adverse weather conditions.

13.3.2.11 Radiological Exposure Control

Planning Standard

> Means for controlling radiological exposures, in an emergency, are established for emergency workers. The means for controlling radiological exposures shall include exposure guidelines consistent with EPA Emergency Worker and Lifesaving Activity Protective Action Guides.

Emergency Plan Evaluation

The applicant has established a radiation protection program for controlling radiological exposures in the event of an emergency. Emergency radiation exposure guidelines have been provided for emergency workers which are consistent with 10 CFR 20 limits and U.S. Environmental Protection Agency's "Manual of Protective Action Guides and Protective Actions for Nuclear Incidents." The plan specifies that the Emergency Director will evaluate any emergency condition that may require emergency personnel to receive radiation exposure in excess of 10 CFR 20 limits and, with the concurrence of the Radiological Director, will be responsible for authorizing voluntary emergency personnel to exceed 10 CFR 20 limits if deemed necessary. Exposure limits are set at 75 rem to the whole body for lifesaving activities and 25 rem to the whole body and 75 rem to the thyroid for protection-of-property activities.

Procedure OEPP01-ZA-0005, "Onsite Radiological Controls," describes the process, including decisionmaking and consideration of risks, for permitting onsite volunteers to receive radiation exposures in the course of carrying out different types of emergency activities.

The applicant has the capability to determine integrated doses received by emergency personnel authorized to wear dosimeters on a 24-hour-per-day basis according to station radiation protection procedures OPRP01 through OPRP10. Emergency supplies include self-reading pocket dosimeters, permanent recording

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thermoluminescent dosimeters, neutron film badge or thermoluminescent dosimeters, and extremity dosimetry badges. Radiation protection personnel issue dosimeters, and maintain and track dose records.

Onsite contamination control measures for personnel and equipment are summarized in the plan and explained in detail in station radiation protection procedures. The criteria for the decontamination of personnel and equipment are specified in the plan. Decontamination facilities are available at the access control point and the EOC. Decontamination facilities are also available at Matagorda General Hospital or Wagner General Hospital for the decontamination of injured personnel. Measures have been provided to control access to contaminated areas and to control drinking and eating in contaminated areas. Criteria have been developed for returning onsite contaminated areas and materials to normal use.

13.3.2.12 Medical and Public Health Support

Planning Standard

> Arrangements are made for medical services for contaminated injured individuals.

Emergency Plan Evaluation

The applicant has made arrangements for the care of injured and contaminated injured personnel with the Matagorda General Hospital in Bay City and the Wagner General Hospital in the City of Palacios. Hospital staff and facilities are trained and equipped to handle contaminated injured patients. Station radiation protection personnel are trained in evaluating radiation exposure and uptake using radiation protection procedures. In addition, the applicant has an agreement with the University of Texas System Cancer Center in Houston for the evaluation and treatment of persons with radiation injuries and injuries with radioactive contamination.

The applicant maintains a first aid station on site that is equipped and staffed to handle temporary care of a patient for treatment of most injuries. Emergency medical teams trained in multi-media first aid are available on a 24-hour-per-day basis to assist injured personnel either at the accident scene or at the first aid facility.

Injured and contaminated injured personnel will be transported to the hospital using a site ambulance or contractor ambulance service. Ambulance crews are trained to handle contaminated patients.

With regard to offsite preparedness, the applicant is required to meet the provisions of the Commission policy on offsite medical services in accordance with the criteria in FEMA Guidance Memorandum MS-1, "Medical Services" (see Information Notice 86-98). Because this is an offsite matter, a finding will be required by FEMA before 5% power is exceeded that the offsite plans are adequate with respect to the above guidance.

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13.3.2.13 Recovery and Reentry Planning and Postaccident Operations

Planning Standard

General plans for recovery and reentry are developed.

Emergency Plan Evaluation

The emergency plan describes the general plans for recovery following an emergency event. Procedures to be used during recovery operations have been developed.

A recovery organization has been established including a Recovery Manager, Recovery Radiological Manager, and Maintenance Manager. The functions and responsibilities of these key positions are described in the plan. The recovery organization will be activated by the Emergency Director. When the decision to enter the recovery phase has been made, station personnel will be informed by a public address announcement and offsite personnel will be informed via radiopager message.

Population doses can be determined from dosimeters retrieved from various locations throughout the plume exposure pathway EPZ. Doses can also be calculated using the cumulative dose file from the EMERXD program of the RM-21A computer.

13.3.2.14 Exercises and Drills

Planning Standard

Periodic exercises are (will be) conducted to evaluate major portions of emergency response capabilities, periodic drills are (will be) conducted to develop and maintain key skills, and deficiencies identified as a result of exercises or drills are (will be) corrected.

Emergency Plan Evaluation

The program of exercises and drills to achieve and maintain an acceptable level of emergency preparedness is described in the emergency plan. Emergency preparedness exercises are to be conducted in accordance with regulatory requirements, that is, annually for onsite response and biennially for offsite participation. The offsite organizations will be invited to participate annually.

Exercises will include specific mobilization of State and county resources adequate to verify the capability to respond to an accident. Scenarios will be varied so that major objectives for the State and county emergency management organizations will be satisfied in accordance with FEMA guidance memorandum PR-1. Exercises during the backshift and under various weather conditions will also be conducted.

The following tests and drills will be conducted according to the schedules given below:

(1) Communication Tests--conducted monthly between the emergency response facilities (control room, TSC, and EOC) and the State and local officials; conducted quarterly with Federal emergency response organizations and the

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State of Texas for the ingestion exposure pathway EPZ, and conducted monthly and during the annual exercise between the emergency centers and offsite field monitoring teams. The communication drills will include the aspect of understanding the content of emergency messages.

(2) Fire Drills--conducted in accordance with FSAR, Fire Hazard Analysis Report, and 10 CFR 50, Appendix R specifications.

(3) Medical Emergency Drill--conducted annually and will include an ambulance service and Matagorda General and Wagner General Hospitals.

(4) Radiological Monitoring Drills--conducted annually.

(5) Health Physics Drills--conducted semiannually.

The plan provides for the development of drill and exercise scenarios that include the basic objectives and appropriate response actions, the simulated events, a time schedule of the events, participating organizations, and a listing of qualified controllers and observers. Input from cognizant station groups and State and county authorities will be used to define the specific objectives to be met during the exercise. Only officials involved in scenario development and approved controllers and observers will share advance knowledge of the scenario.

All drill and exercises will be followed by a critique. The Manager, Emergency Preparedness Department, is responsible for followup coordination on all exercise critique comments and will ensure implementation of corrective actions.

An exercise of the onsite and offsite emergency plans for the South Texas Project was conducted on April 8, 1987. NRC Region IV staff will ensure that all emergency preparedness inspection items identified during the exercise have been satisfactorily completed. FEMA will report its findings to the NRC before full-power operation is authorized.

13.3.2.15 Radiological Emergency Response Training

Planning Standard

Radiological emergency response training is provided to those who may be called on to assist in an emergency.

Emergency Plan Evaluation

The applicant has established an emergency training and qualification program, which is summarized in the emergency plan. The training program includes general emergency plan orientation for all persons at the site and specific training for members of the emergency response organizations. Provisions have been made for the initial training and periodic retraining of emergency response personnel. Besides classroom training, the training includes participation in practical drills with on-the-spot correction of erroneous performance and demonstrations of proper performance. Written examinations will be given to all members of the emergency organization.

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The emergency plan lists functional roles in the onsite emergency response organization for which training requirements have been established. The plan indicates the specific training requirements for the emergency response organization by functional roles including directors and managers, radiation emergency teams, control room operations staff, radiological assessment personnel, and communicators. As indicated in the emergency plan training matrix, eight courses have been developed covering various aspects of emergency response.

The emergency plan also specifies the offsite emergency organization training program for the fire departments, ambulance personnel, police departments, and hospital staffs relied on in an emergency. Training for offsite agencies consists of notification procedures, radiation protection, and specific responsibilities for each group being trained. Station personnel also will provide training to State and local emergency personnel.

13.3.2.16 Responsibility for the Planning Effort: Development, Periodic Review, and Distribution of Emergency Plans

Planning Standard

Responsibilities for plan development and review and for distribution of emergency plans are established, and planners are properly trained.

Emergency Plan Evaluation

The Vice President, Nuclear Plant Operations, has the overall authority and responsibility for emergency response planning at the South Texas Project. The Manager, Emergency Preparedness Department, provides direction for the development and updating of emergency plans and the coordination of these plans with other response organizations. The Emergency Preparedness Department is responsible for the development and maintenance of the station emergency plan. These personnel will receive training on site and by attending various offsite seminars and training sessions.

The station emergency preparedness program including letters of agreement will be reviewed on an annual basis and updated as appropriate. The results of the emergency preparedness program review will be submitted by the Manager, Emergency Preparedness Department, to the Plant Operations Review Committee (PORC) for review. After the PORC review, the Plant Manager will approve recommendations for improvement. Deficiencies identified during drills or exercises will be resolved by the Plant Manager. The Manager, Emergency Preparedness Department, will ensure implementation of those recommendations approved. Emergency plan revisions are dated and marked to show where changes have been made, and copies are forwarded to all controlled copy holders. Telephone numbers in emergency procedures are reviewed quarterly and corrected as necessary.

The plan lists the State of Texas Emergency Management Plan and the Emergency Management Plan for Matagorda County, Bay City, and the City of Palacios as the supporting emergency plans. Attachment 2 to the plan contains a listing by title of procedures that implement the plan and the corresponding section of the plan. Attachment 1 contains a cross-reference from emergency plan sections to the criteria in NUREG-0654. A specific table of contents is included in the plan.

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An audit will be performed by the Station Quality Assurance Department at least once each year. The audit addresses all aspects of the emergency preparedness program including the plan, implementing procedures, training program, drill and exercise results, review recommendations, records management, and maintenance of equipment. The results of all reviews will be documented and forwarded to the Manager, Emergency Preparedness Department, the Plant Manager, and the Vice President, Nuclear Plant Operations. Documents applicable to reviews of the emergency preparedness program will be retained for at least 5 years.

An annual review of the emergency preparedness program will be performed under the auspices of the Nuclear Safety Review Board by knowledgeable personnel who are independent of the Station Emergency Preparedness Department.

13.3.3 Conclusion

On the basis of a review of the South Texas Project Electric Generating Station Emergency Plan for conformance with the criteria in NUREG-0654/FEMA-REP-1, the staff concludes that the South Texas Project emergency plan provides an adequate planning basis for an acceptable state of onsite emergency preparedness and meets the requirements of 10 CFR 50 and Appendix E thereto for issuance of a license authorizing fuel loading and operation up to 5% of rated power.

After receiving the findings and determination made by FEMA on State and local emergency response plans and preparedness, the staff will provide an overall conclusion on the status of onsite and offsite emergency preparedness for the South Texas Project in a supplement to the SER before authorizing operation above 5% of rated power.

13.5 Plant Procedures

13.5.1 Administrative Procedures

In the SER, the staff identified seven station operating procedures that were not available when the SER was published but that were to be examined by the staff to confirm the applicant's commitments before licensing. During the March 3-6, 1987 site visit, the applicant made copies of the procedures available for staff inspection. On the basis of the following, confirmatory item 25 is closed.

13.5.1.1 Shift Supervisor Responsibilities

Station operating procedure OPGP08-ZO-0004 sets forth the shift supervisor's responsibilities and defines the authority and responsibilities of the other members of the shift crew. The applicant has established but has not filled the shift administrative aide positions. This procedure meets Items I.A.1.2 and I.C.3 of NUREG-0694 and is acceptable. This item, therefore, is closed.

13.5.1.2 Control Room Access

Station operating procedure OPGP03-ZO-0004 specifically limits access to the control room. It also establishes the line of authority, responsibility, and succession in the control room. This procedure meets Item 1.C.4 of NUREG-0694 and is acceptable. This item, therefore, is closed.

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13.5.1.3 Limits on Working Hours

The applicant's policy on working hours, applicable to most plant personnel performing safety-related functions, is stated in station procedure OPGP03-ZO-0004. The Technical Specifications set forth specific restrictions governing working hours of the unit staff. These meet Item I.A.1.3 of NUREG-0737. This item, therefore, is closed.

13.5.1.4 Shift Relief/Turnover Requirements

The staff examined two procedures prescribing shift relief and turnover procedures--one for Reactor Operations Division and one for the Chemical Operations and Analysis Division. These procedures meet NUREG-0694, Item I.C.2, and are acceptable. This item, therefore, is closed.

13.5.1.5 Operating Experience Feedback

Procedure IP-2.20, Revision 2, dated October 1, 1985, describes the methods to be used to screen operating experience information for applicability to the South Texas Project, to ensure information for applicability to the South Texas Project, and to ensure that lessons learned are translated into appropriate actions to enhance the plant's safety and reliability. Staff review of procedure IP-2.20 indicates that it provides an adequate mechanism for feedback of operating experience, thus meeting Item I.C.5 of NUREG-0694 and NUREG-0737. This item, therefore, is closed.

13.5.1.6 Verification of Correct Performance of Operating Activities

The staff reviewed procedure OGP03-ZA-0010, which describes the methods by which independent verifications of operating activities are performed. As required by the procedure, the verifications will be performed by qualified individuals acting independently and must normally provide positive assurance that the activities have been performed correctly. This meets Item I.C.6 of NUREG-0737 and is acceptable. This item, therefore, is closed.

13.5.1.7 Crane Operations

The staff examined procedure OGP03-ZA-0069, which prescribes the procedures governing movement of heavy loads. The procedure establishes special requirements to control the movement of loads in the reactor containment building and in the fuel handling building. The staff concludes that this procedure satisfies the requirement for the establishment of controls governing crane operations. This item, therefore, is closed.

13.6 Industrial Security

13.6.1 Introduction

The applicant has filed with the NRC the following security plans, which have since been amended: "South Texas Project Electrical Generating Station Physical Security Plan," "South Texas Project Electrical Generating Station Safeguards Contingency Plan," and "South Texas Project Electrical Generating Station Security Personnel Qualification and Training Plan."

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The staff's safety evaluation summarizes how the applicant has provided for meeting the requirements of 10 CFR 73. The staff's evaluation consists of a basic analysis that is available for public review, a protected appendix, and a protected response force size worksheet.

On the basis of its review of the subject documents and visits to the site, the staff has concluded that the protection provided by the applicant against radiological sabotage at South Texas meets 10 CFR 73. Accordingly, the protection provided will ensure that the health and safety of the public will not be endangered, and Open Item 14 on security is closed.

Table 13.1 is a chronology of the approved plans' evolution; it should be maintained with the safeguards plans, separate from the license. This documentation, in addition to establishing a record of current safeguards amendments, provides assistance in the inspection effort.

13.6.2 Physical Security Organization

To satisfy 10 CFR 73.55(b), the applicant has provided a physical security organization that includes the position of security shift supervisor. A person filling that position will be on site at all times with the authority to direct the physical protection activities. To implement the commitments made in the physical security, personnel qualification and training, and safeguards contingency plans, written security procedures specifying the duties of the security organization members are available for inspection. The training program and critical security tasks and duties for the security organization personnel are defined in the "South Texas Project Electrical Generating Station Security Personnel Qualification and Training Plan," which meets 10 CFR 73, Appendix B, for the training, equipping, and qualification of the security organization members. The physical security plan and the training program provide commitments that preclude the assignment of any individual to a security-related duty or task before the individual is trained, equipped, and qualified to perform the assigned duty in accordance with the approved training and qualification plan.

13.6.3 Physical Barriers

To meet 10 CFR 73.55(c), the applicant has provided a protected area barrier that meets the definition of 10 CFR 73.2(f)(1). An isolation zone, to permit observation of activities along the barrier, of at least 20 feet is provided on both sides of the barrier with the exception of the locations listed in the protected appendix. The staff has reviewed those locations and determined that the security measures in place are satisfactory and continue to meet 10 CFR 73.55(c).

Illumination of 0.2 foot-candle is maintained for the isolation zones, protected area barrier, and external portions of the protected area. In areas where illumination of 0.2 foot-candle cannot be maintained, special procedures are applied as described in the protected appendix.

The protected area is patrolled at random intervals to detect the presence of unauthorized persons, vehicles, and materials.

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Identification of Vital Areas

The protected appendix discusses the applicant's vital area program and identifies those areas and items of equipment determined to be vital for protection purposes. Vital equipment is located within vital areas that are located within the protected area and that require passage through at least two barriers, as defined in 10 CFR 73.2(f)(1) and (2), with certain exceptions, to gain access to vital equipment. The staff has reviewed those exceptions and has determined that the barriers are sufficiently substantial to meet the intent of the two-barrier requirement.

Except for the exceptions noted in the protected appendix, vital area barriers are separated from the protected area barrier. The control room and central alarm station are provided with bullet-resistant walls, doors, ceilings, floors, and windows. On the basis of these findings and the analysis in the protected appendix, the staff has concluded that the applicant's program for identifying and protecting vital equipment satisfies the regulatory intent. However, this program is subject to onsite validation by the staff in the future and to subsequent changes if they are found to be necessary.

13.6.4 Access Requirements

In accordance with 10 CFR 73.55(d), all points of personnel and vehicle access to the protected area are controlled. The individual responsible for controlling the final point of access into the protected area is located in a bullet-resistant structure. As part of the access control program, vehicles (except under emergency conditions), personnel, packages, and materials entering the protected area are searched for explosives, firearms, and incendiary devices by means of electronic search equipment.

Vehicles admitted to the protected area, except applicant-designated vehicles, are controlled by escorts. Applicant-designated vehicles are limited to onsite station functions and remain in the protected area except for operational maintenance, repair, security, and emergency purposes. Positive control over these vehicles is maintained by personnel authorized to use the vehicles or by the escort personnel.

A picture badge/key card system, utilizing encoded information, identifies individuals that are authorized unescorted access to protected and vital areas and is used to control access to these areas. Individuals not authorized unescorted access are issued non-picture badges that indicate an escort is required. Access authorizations are limited to those individuals who have a need for access to perform their duties.

Unoccupied vital areas are locked and alarmed. Access to the reactor containment is positively controlled to ensure that only authorized individuals are permitted to enter. In addition, all doors and personnel/equipment hatches into the reactor containment are locked and alarmed. Keys, locks, combinations, and related equipment are changed on an annual basis. In addition, when an individual's access authorization has been terminated because of lack of reliability or trustworthiness or because of poor work performance, the keys, locks, combinations, and related equipment to which that person had access are changed.

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13.6.5 Detection Aids

In satisfying 10 CFR 73.55(e), the applicant has installed intrusion detection systems at the protected area barrier, at entrances to vital areas, and at all emergency exits. Alarms from the intrusion detection system annunciate within a secondary alarm station also located in the protected area. In addition, the central alarm station is constructed so that the walls, floors, ceilings, doors, and windows are bullet resistant. The alarm stations are located and designed in such a manner so that a single act cannot interdict the capability of calling for assistance or responding to alarms. No other functions or duties that would interfere with its alarm response function are performed in the central alarm station.

The intrusion detection system's transmission lines and associated alarm annunciation hardware are line supervised and tamper indicating. Alarm annunciators indicate the type of alarm and its location when activated. An automatic indication of when the alarm system is on standby power is provided in the central alarm station.

13.6.6 Communications

As required in 10 CFR 73.55(f), the applicant has provided for continuous communications between the central and secondary alarm station operators, guards, watchmen, and armed response personnel through the use of a conventional telephone system and a security radio system. In addition, direct communication with the local law enforcement authorities is maintained through the use of a conventional telephone system and a two-way FM radio link.

All nonportable communication links, except the conventional telephone system, are provided with an uninterruptible emergency power source backed up by diesel generators.

13.6.7 Test and Maintenance Requirements

To meet 10 CFR 73.55(g), the applicant has established a program for the testing and maintenance of all intrusion alarms, emergency alarms, communication equipment, physical barriers, and other security-related devices or equipment. Equipment or devices that do not meet the design performance criteria or have failed to otherwise operate will be compensated for by appropriate measures as defined in the security plan and in site procedures. The compensatory measures defined in the plan will ensure that the effectiveness of the security system is not reduced by failures or other occurrences affecting the operation of the security-related equipment or structures.

Intrusion detection systems are tested for proper performance at the beginning and end of any period during which they are used for security. Such testing will be conducted at least once every 7 days.

Communication systems for onsite communication are tested at the beginning of each security shift. Offsite communication systems are tested at least once each day.

Audits of the security program are conducted once every 12 months by the Manager of Quality Assurance, who is independent of site security management and

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supervision. The audits, focusing on the effectiveness of the physical protection provided by the onsite security organization in implementing the approved security program plans, include, but are not limited to, a review of the security procedures and practices, system testing and maintenance programs, and local law enforcement assistance agreements. The Manager of Quality Assurance prepares a report documenting the findings and recommendations and submits it to a corporate vice president for review and necessary action.

13.6.8 Response Requirements

To meet 10 CFR 73.55(h), the applicant has provided for armed personnel immediately available for response duties on all shifts consistent with the requirements of the regulations (as described in the protected appendix). Considerations used in support of this number are attached to the appendix. In addition, liaison with local law enforcement authorities to provide additional response support in the event of security-related events has been established and documented.

The applicant's safeguards contingency plan for dealing with thefts, threats, and radiological sabotage events satisfies 10 CFR 73, Appendix C. The plan identifies appropriate security events that could initiate a radiological sabotage event and identifies the applicant's preplanning, response resources, safeguards contingency participants, and coordination activities for each event. Through this plan, on the detection of unauthorized presence or activities within the protected or vital areas, response activities using the available resources would be initiated. The response activities and objectives include the neutralization of the existing threat by requiring the response force members to interpose themselves between the adversary and the objective, instructions to use force commensurate with that used by the adversary, and authority to request sufficient assistance from the local law enforcement authorities to maintain control over the situation.

13.6.9 Employee Screening Program

To meet the requirements of 10 CFR 73.55(a) to protect against the design-basis threat as stated in 10 CFR 73.1(a)(1)(ii), the applicant has provided for an employee screening program. Personnel who successfully complete the employee screening program or its equivalent may be granted unescorted access to protected and vital areas at the site. All other personnel requiring access to the site are escorted by persons who have been authorized and trained for escort duties and who have successfully completed the employee screening program. The employee screening program is based on accepted industry standards and includes a background investigation, psychological evaluation, and a continuing observation program.

The plan also provides for a "grandfather clause" exclusion, which allows recognition of a certain period of trustworthy service with the utility or contractor as being equivalent to the overall employee screening program. The staff has reviewed the applicant's screening program against the accepted industry standard (American National Standards Institute Standard ANSI N18.17-1973) and has determined that the program is acceptable.

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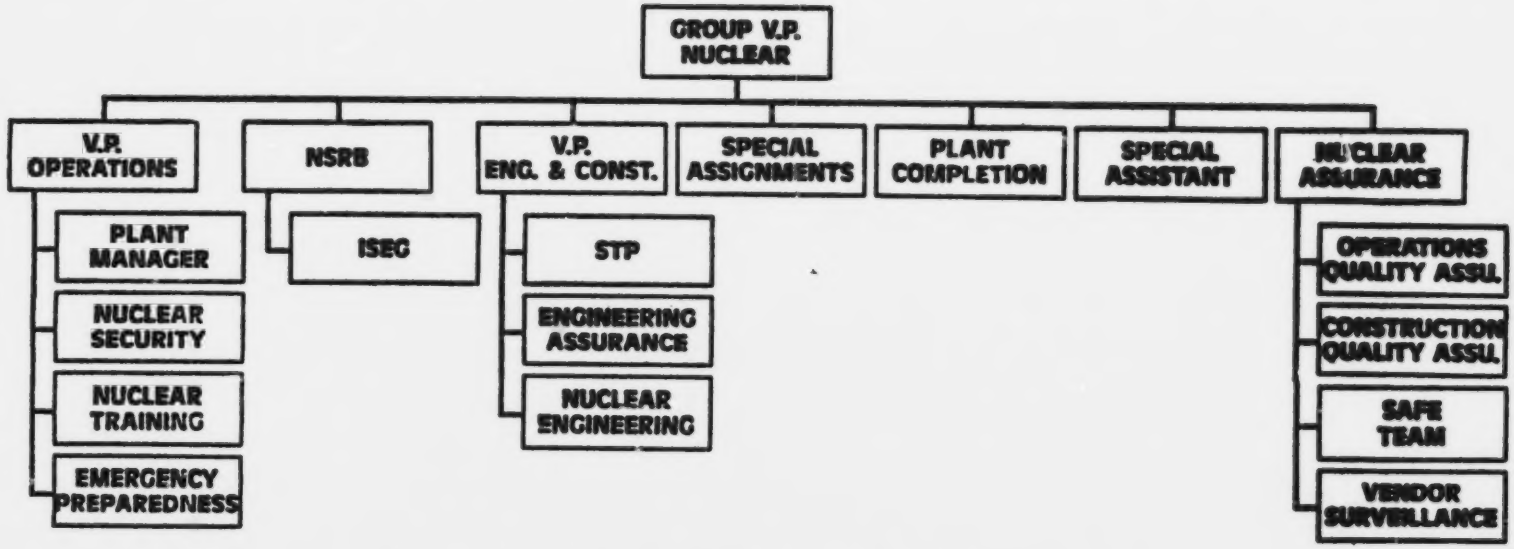

Figure 13.1 Organizational structure in March 1987

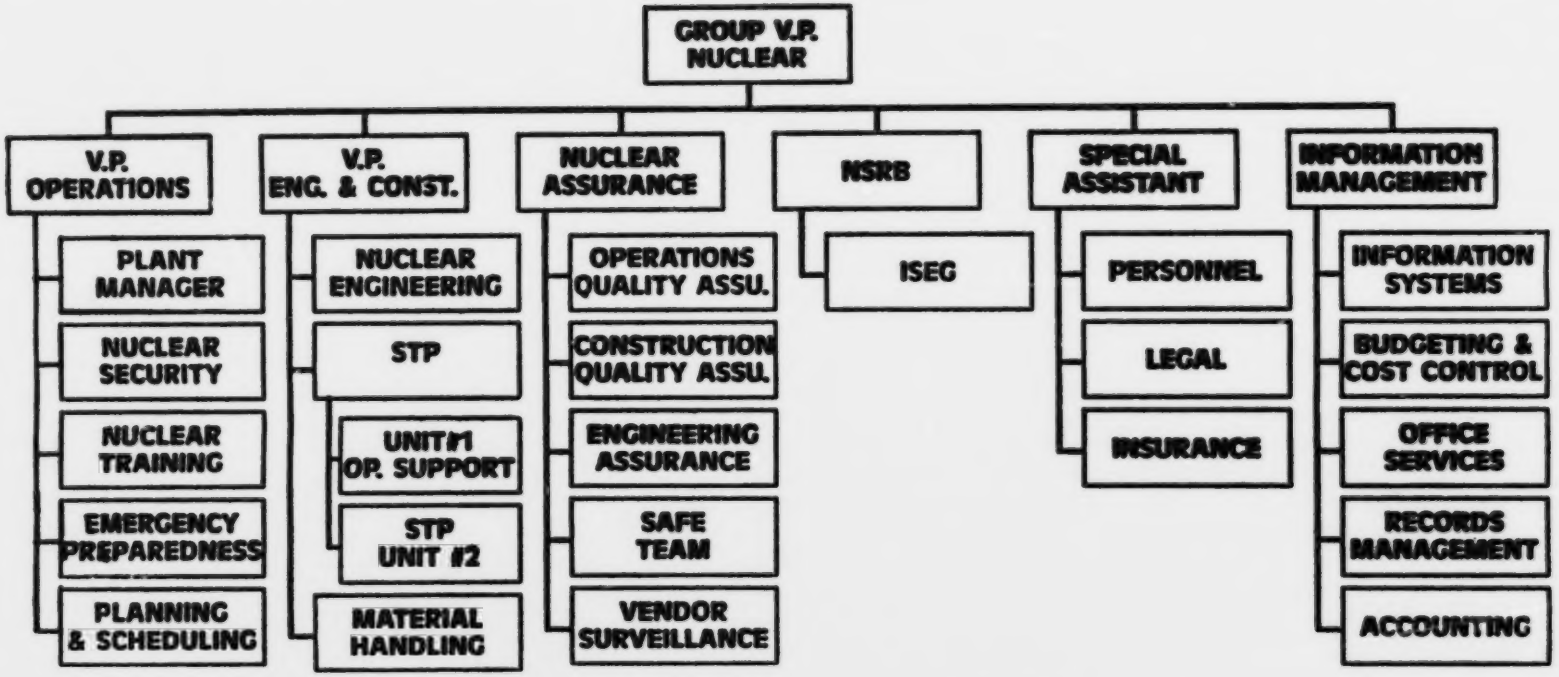

Figure 13.2 Organizational structure from April 1, 1987 through start of commercial operation of Unit 1

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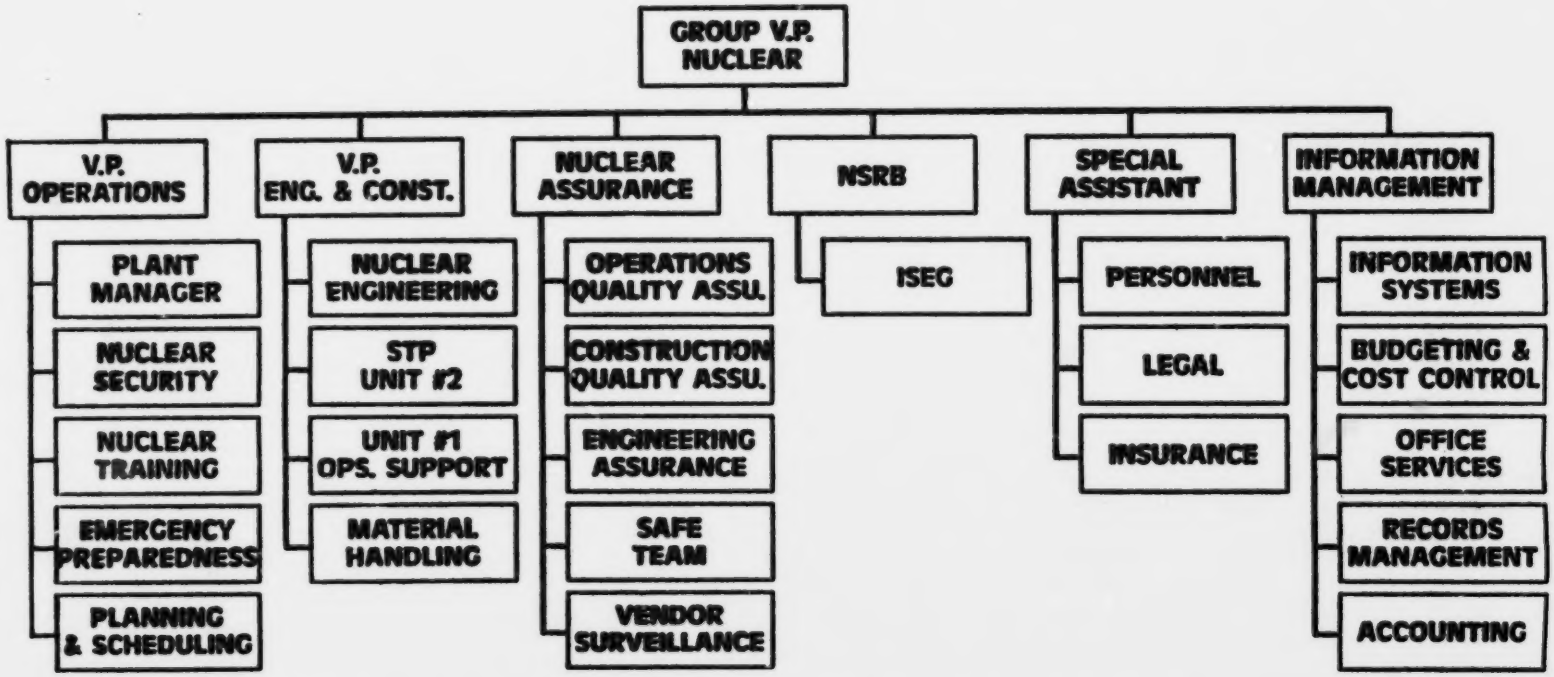

Figure 13.3 Planned organizational structure from start of commercial operation of Unit 1 through completion of Unit 2

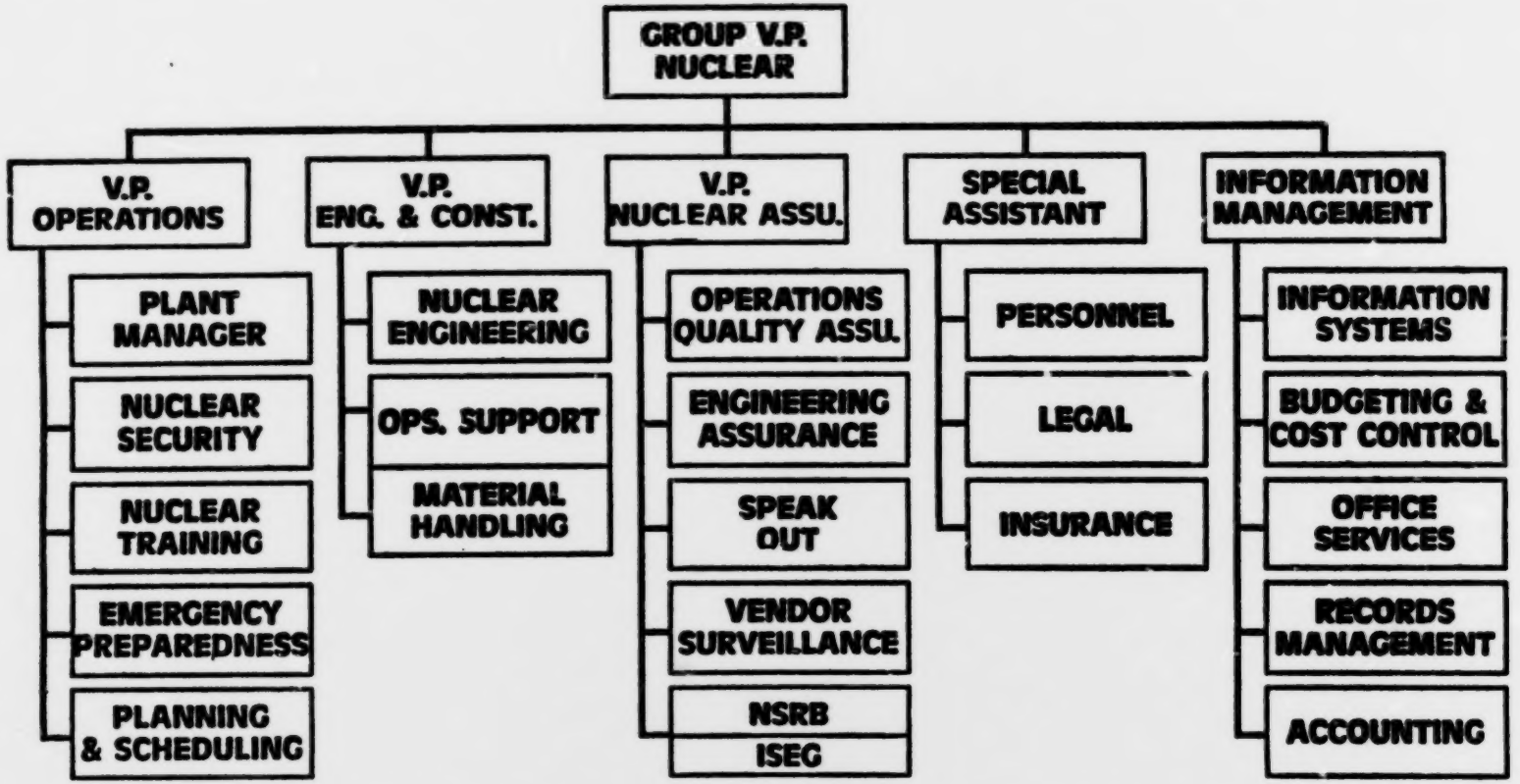

Figure 13.4 Planned organizational structure after Unit 2 is completed

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Table 13.1 Chronology of the evolution of the approved security plans--South Texas Unit 1

Plan and revision	Date	Transmitted by letter dated
Security Plan		
Rev 1	May 1, 1979	May 1, 1979
Rev 2	June 1, 1981	July 17, 1981
Rev 3	May 1983	May 27, 1983
Rev 4	March 1985	March 29, 1985
Rev 5	March 1986	March 11, 1986
Rev 6	January 1987	February 3, 1987
Rev 7	March 1987	March 20, 1987
Training and Qualifications Plan		
Rev 0	July 15, 1981	August 21, 1981
Rev 1	May 1982	May 13, 1982
Rev 2	April 1984	April 24, 1984
Rev 3	March 1985	March 29, 1985
Rev 4	March 1986	March 11, 1986
Rev 5	May 1986	May 5, 1986
Rev 6	January 1987	February 3, 1987
Rev 6	March 1987	March 12, 1987
Rev 7	March 1987	March 20, 1987
Contingency Plan		
Rev 1	May 1, 1979	May 1, 1979
Rev 2	June 1, 1981	July 17, 1981
Rev 3	May 1983	May 27, 1983
Rev 4	March 1985	March 29, 1985

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15 ACCIDENT ANALYSIS

15.4 Reactivity and Power Distribution Anomalies

15.4.6 Inadvertent Boron Dilution

In the SER, the staff noted that the applicant had not submitted boron dilution analyses for the hot and cold shutdown modes (modes 4 and 5) and also requested additional information regarding the analytical model used in these calculations. SRP Section 15.6.4 (NUREG-0800) states that if operator action is required to terminate the transient, a minimum of 15 minutes must be available between the time when an alarm announces an unplanned moderator dilution and the time of loss of shutdown margin for all modes except refueling (mode 6). During refueling 30 minutes are required. Operator action would include finding and isolating the source of dilution and initiating boration if necessary. In the SER, the staff indicated that the analytical results for modes 4 and 5 may bound those for modes 1, 2, and 3.

In letters dated September 30, 1986 and January 26, 1987, the applicant provided additional information, including analyses for modes 3, 4, and 5, additional information on the analytical model, and a revised list of alarms and indications for a dilution event. A failure modes and effects analysis was included, which considered each potential dilution path for the shutdown modes (modes 3, 4, and 5). The reactor makeup water system was identified as the bounding and most likely dilution source. Calculations were performed to determine the minimum shutdown margin to meet the required 15-minute operator response time between actuation of a neutron flux multiplication alarm and loss of shutdown margin. These calculations assume the most reactive control rod in its fully withdrawn position. Two extended-range neutron flux detectors will be provided with flux multiplication alarms set at 1.5 times the initial count rate. However, the alarm was conservatively assumed to respond at 2 times the initial rate for calculational purposes For modes 3 and 4 (hot standby and hot shutdown), with at least one reactor coolant pump (RCP) operating, and based on an effective dilution volume of 11,252 ft^3 (reactor coolant system (RCS) volume exclusive of the pressurizer), the maximum dilution rate that allows 15 minutes between alarm actuation and loss of shutdown margin is 250 gpm. This maximum flowrate is limited by system design (i.e., the maximum flowrate through flow control valve FCVIIIA is about 240 gpm, and the maximum valve bypass flow through the normally isolated chemical mixing tank is about 10 gpm) and administrative means (i.e., locking valve CV 0215 closed).

For mode 4 with no RCP operating, and for mode 5A (defined as cold shutdown with reactor and RCS loops filled), operation of one residual heat removal train was assumed. The total dilution volume was assumed to be 5355 ft^3, which includes the reactor vessel liquid volume exclusive of the upper head, and one RCS loop. A maximum dilution rate of 125 gpm would be allowed in order to satisfy the 15-minute operator action time. To accomplish this, manual valve CV 0198 would be throttled and locked or pinned in a position that would ensure that the maximum allowable dilution flowrate would not be exceeded. This requirement will be included in the South Texas Technical Specifications. For

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modes 5B (cold shutdown--RCS not completely filled) and 6 (refueling), dilution would be prevented administratively by locking closed valves FCV 110B (in normal reactor makeup water (RMW) line to charging pump suction), FCV 111B (in RMW line to top of volume control tank), CV 0201A (chemical mixing tank isolation valve), CV 0215 (emergency boration flush line isolation valve), and CV 0221 (alternate emergency boration isolation valve). This requirement will also be included in the Technical Specifications.

For modes 1 and 2, a dilution rate of 382 gpm, the combined capacity of two RMW pumps, was conservatively assumed, although the dilution flowrate would actually be limited to 250 gpm as in mode 3. While in mode 1 (power mode) and in automatic control, the rod insertion limit alarms would provide the operator with approximately 27 minutes to take action before shutdown margin is lost. With the reactor in manual control, the overtemperature ΔT ($OT\Delta T$) alarm would be actuated, followed by $OT\Delta T$ trip. The operator would have about 17 minutes available to take action after reactor trip. When the reactor is in mode 2 (startup mode), a reactor trip at the power range high neutron flux low setpoint provides the operator with about 20 minutes to take action.

The applicant states that no fuel damage would occur as a result of this event, and that radiological consequences would be minimal. The staff concludes that the applicant has adequately demonstrated that operator action can be taken for all modes within the times required in SRP Section 15.4.6 and has submitted the additional information requested regarding the analytical model. The staff finds the applicant's analyses acceptable. Open Item 15 is therefore closed.

15.6 Decrease in Reactor Coolant Inventory

15.6.5 Loss-of-Coolant Accident Resulting From Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary

15.6.5.1 Loss-of-Coolant Accident

Generic Letter 85-12

In SSER 1, the staff identified six confirmatory items regarding the Generic Letter 85-12 issue concerning reactor coolant pump (RCP) trip. Most of the confirmatory items dealt with the information received in a letter dated May 30, 1986 from the applicant. On the basis of recent submittals from the applicant, dated September 30 and December 5, 1986, the staff concludes that these six confirmatory issues have been resolved. Each confirmatory item is restated and its resolution is discussed below.

(1) Selected RCP trip criteria should be provided, including numerical values, final uncertainties, final calculated results, and a comparison of the selected criterion with the calculations that illustrate application of the uncertainties and establish the separation between LOCA and non-LOCA events.

In a letter dated September 30, 1986, the applicant stated that the RCP trip criterion selected for use at South Texas is reactor coolant system (RCS) pressure. In the letter dated December 5, 1986, the applicant stated that the RCP trip setpoint based on the RCS pressure criterion is 1492 psia for both

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normal and adverse containment conditions. The RCS pressure instrument (from the sensor through the pressure transmitter) uncertainty under normal conditions is 81.2 psi. Since the pressure transmitters are located outside the containment and would not be subjected to adverse containment conditions, the applicant stated that the instrument uncertainty is the same for both normal and adverse containment conditions. The staff finds this acceptable.

The previously approved Westinghouse LOFTRAN computer code was used to perform the alternative RCP trip criteria analyses. Both steam generator tube rupture (SGTR) and non-LOCA events were analyzed. The major causes of uncertainties and conservatism in the LOFTRAN code include break flowrates, safety injection flowrates, decay heat, and auxiliary feedwater flowrates. The applicant stated that when Westinghouse did the generic study, South Texas was singled out as a separate plant category so that there was no need to have a plant-specific analysis in addition to the generic study. The results showed a smaller overall uncertainty for the RCS pressure trip setpoint for South Texas than for other Westinghouse plants. The applicant attributed this primarily to the small effect of safety injection system performance on the uncertainty resulting from the South Texas safety injection system design. The staff finds this acceptable. In addition, on the basis of the approved Westinghouse generic study, the staff concludes that the RCP trip setpoint based on the RCS pressure is capable of preventing an unneeded RCP trip for South Texas. The staff, therefore, concludes that this confirmatory item is resolved.

(2) Describe the impact of an adverse containment atmosphere on RCS pressure indication.

As indicated in the letter dated September 30, 1986, the pressure transmitters are located outside the containment and are safety related and fully qualified. The pressure transmitters are thus not subjected to adverse containment conditions. In addition, the applicant stated that, on the basis of the selected break locations, no more than one RCS pressure instrument channel will be affected by small-break LOCAs. The remaining two RCS pressure instrument channels can provide adequate pressure readings to the operator. The staff, therefore, concludes that the effect of an adverse containment on RCS pressure indication is insignificant, and this confirmatory item is resolved.

(3) Identify the specific instrumentation used to determine the need for RCP trip.

In the letter dated September 30, 1986, the applicant stated that three RCS wide-range pressure channels are selected to monitor all possible conditions for providing the operator with adequate pressure indication when RCP trip is required. The staff concludes that these three pressure channels are adequate, and this confirmatory item is resolved.

(4) Summarize the program to evaluate pipe whip and fluid jets insofar as impact on RCS trip is concerned.

As stated in the letter dated September 30, 1986, the applicant will conduct a walkdown in May 1987, which is part of the confirmation of the high energy line break analysis and any adverse interactions identified will be corrected (e.g., additional protection to mitigate the interaction). On the basis of the

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applicant's commitment, the staff concludes that the concern of pipe whip and fluid jets related to RCP trip is adequately addressed, and this confirmatory item is resolved.

(5) Define the radiation environment associated with an adverse containment.

The definition of an adverse containment environment at South Texas is considered to correspond to a Hi-1 containment isolation signal, which is received at a pressure of 5.5 psig. The applicant considers that there is no need to have a radiation environment associated with the adverse containment because all the pressure transmitters are located outside the containment. The staff finds this acceptable. Therefore, this confirmatory item is resolved.

(6) Describe the results of the program to evaluate pipe breaks insofar as it affects RCP trip considerations.

As indicated in Item 2, there is adequate redundancy of pressure instrument readings available to the operator because no more than one RCS pressure instrument channel can be affected by a small-break LOCA. The applicant also indicated that (a) all components associated with RCP trip are located outside the containment, (b) there is no high energy line passing through the control room, and (c) the reactor coolant pump breakers are protected in the turbine building. Therefore, the potential effect of pipe breaks on RCP trip is small. The staff, therefore, concludes that the effect of pipe breaks on the RCP trip issue is adequately addressed, and this confirmatory issue is resolved.

Conclusion

The applicant has satisfactorily addressed each of the points identified in Confirmatory Item 35. The staff considers the applicant's treatment of RCP trip acceptable and thus Confirmatory Item 35 is resolved for South Texas Units 1 and 2.

15.6.5.1.1 Large-Break-LOCA Analysis

In the SER, the staff provided the evaluation of the large-break-LOCA analysis using the December 1981 BART evaluation model. The most limiting event was found to be a cold-leg double-ended guillotine break with a Moody discharge coefficient (C_D) of 0.6. A maximum peak cladding temperature (PCT) of 1981°F resulted from operation of all three safety injection (SI) trains (maximum SI case).

In a letter dated August 22, 1986, the applicant provided a revised evaluation that included modeling of fuel assembly control rod guide thimbles, removal of a hot assembly power adjustment, and heat transfer model improvements. These modifications to the BART program are contained in Westinghouse report WCAP-9561 and were approved by the staff in a letter from C. E. Rossi dated August 25, 1986. The letter dated August 22, 1986 from the applicant also included the effects of revised accumulator volume (from 1580 ft^3 to 1200 ft^3). The analysis assumed a maximum of four reactor containment fan coolers (RCFCs) operating. However, it was indicated that assuming operation of all six RCFCs would result in a higher PCT, since this would cause a decrease in containment pressure and a decreased core flooding rate.

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In a letter dated March 26, 1987, the applicant provided a revised analysis assuming operation of six RCFCs, revised heat sink data, use of SI flows measured during startup testing, and initiation of component cooling water (CCW) flow on SI actuation. Both maximum and minimum SI cases were evaluated. The most conservative results were obtained with maximum SI flow and $C_D = 0.6$. For this case PCT was calculated to be 2094°F, maximum local zirconium-water (Zr/H_2O) reaction 6.35%, and total Zr/H_2O reaction less than 0.3%.

The applicant has analyzed the performance of the emergency core cooling system (ECCS) for the large-break LOCA in accordance with 10 CFR 50.46 and Appendix K to 10 CFR 50, using an approved model. The staff concludes that the ECCS design is acceptable with regard to the capability to mitigate the consequences of a postulated large-break LOCA. Confirmatory Item 43 is therefore closed.

15.6.5.1.2 Small-Break-LOCA Analysis

In the SER, the staff noted that the applicant had submitted analyses for a spectrum of small-break LOCAs performed for the initial 1500 seconds of the event. The analyses, which were performed using the WFLASH code, identified the 4-in. break as limiting with a calculated PCT of 1201°F. As indicated in SER Section 15.6.5, in response to TMI Item II.K.3.31, the applicant was required to reanalyze the small-break-LOCA event utilizing the NOTRUMP code. Furthermore, in SER Section 6.3.5.2, the staff noted its concern regarding the long-term mitigation of small-break LOCAs of such a size that recirculation would be required but the reactor coolant system pressure would remain above the low head safety injection (LHSI) pump shutoff head, since the South Texas emergency core cooling system (ECCS) is not designed for high head recirculation combined with residual heat removal (RHR) heat exchanger decay heat removal (i.e., the LHSI and high head safety injection (HHSI) pumps cannot be operated in series) The RHR system is located inside the containment. No credit was taken for RHR pump qualification for the postaccident environmental conditions from a small-break LOCA or secondary system break inside the containment. The auxiliary feedwater storage tank (AFST) is not backed up by a safety-grade water supply system and, therefore, the secondary heat sink has a limited assured supply. The staff was concerned that, for certain size small-break LOCAs, insufficient energy would be removed from the break until some time after loss of the secondary heat sink.

As discussed in the SER, the applicant provided generic long-term post-LOCA cooldown analyses based on WCAP-9600. It was indicated that, for 4-in. breaks or smaller, the reactor coolant system (RCS) pressure would stay above the LHSI pump shutoff head without operator action For breaks 1 in. or larger, all decay heat could be removed via the break before secondary heat sink depletion occurred. The steam evolved would be condensed by the reactor containment fan coolers (RCFCs). For breaks larger than 3/8 in. and less than 1 in., the steam generators (SGs) could provide adequate decay heat removal provided the AFST supply was replenished from the essential cooling pond (ECP) by temporary piping or hose. As an alternative, heat removal might be accomplished by cooling down and depressurizing the RCS and then utilizing the LHSI pumps in combination with the RHR heat exchangers. For isolable LOCAs and secondary breaks, the containment sumps would not be available for LHSI pump supply, and an environmentally qualified RHR system would be required to ensure that cold shutdown conditions would be achieved. The applicant committed to perform more detailed analyses for small-break LOCAs utilizing plant-specific conditions

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and up-to-date codes in order to demonstrate that the ECCS meets 10 CFR 50.46 for long-term decay heat removal. The applicant subsequently informed the staff that the RHR pumps are environmentally qualified. This is still under staff review. If found acceptable, this would obviate the need for temporary piping from the ECP to the AFST.

TMI Action Plan Item II.K.3.31

Item II.K.3.30 of NUREG-0737 outlines the Commission requirements for light-water-reactor vendors to demonstrate that their small-break-LOCA analysis methods continue to comply with the requirements of Appendix K to 10 CFR 50. The technical issues to be addressed were listed in NUREG-0611 including comparison with Semiscale and LOFT experimental test results. In response to Item II.K.3.30, the Westinghouse Owners Group (WOG) submitted generic analyses using the NOTRUMP code, which is the new licensing small-break-LOCA model. The NOTRUMP code and methodology were described in WCAP-10079 and WCAP-10054. The code was evaluated and approved by the staff (Thomas, May 21, 1985). In the SER, the staff stated that the WOG intended to submit generic analyses for different plant types in response to TMI Action Plan Item II.K.3.31. The staff found this acceptable. Because the South Texas design is unique, the applicant submitted a plant-specific analysis in a letter dated December 18, 1986.

Referencing the new computer code did not imply deficiencies in the WFLASH code (which was previously utilized for small-break-LOCA analysis) so that the code did not comply with Appendix K to 10 CFR 50. The decision to use NOTRUMP was based on performing licensing evaluations with a computer program specifically designed to calculate small-break LOCAs with greater phenomenological accuracy than is possible by using WFLASH.

The applicant's letter of December 18, 1986 is an analysis for a spectrum of small-break-LOCA analyses (3, 4, and 6 in.). These identify the 4-in. break as the limiting small break; the calculated peak cladding temperature is 1366°F at 86 seconds, the local metal-water reaction is 0.28%, and the corewide oxidation is less than 0.3%. The applicant's results are well below all the acceptance criteria limits of 10 CFR 50.46. The staff has reviewed the applicant's evaluation and concludes that it is acceptable and that the applicant has met the requirements of TMI Action Plan Item II.K.3.31.

Postaccident Cooldown Evaluation

In a letter dated September 30, 1986 and in WCAP-11232, the applicant provided detailed long-term analyses for a 1.5-in.-break LOCA, a 0.7-in.-break LOCA, and a feedline break. The first analysis (1.5-in. break) bounds larger breaks for the long term because sufficient cooling would be provided by the break flow, safety injection, and secondary heat sink for decay heat removal. The second analysis (0.7-in. break) was chosen to represent smaller breaks that may not achieve adequate long-term heat removal from safety injection and break flow. The third analysis (feedline break) bounds isolable LOCAs as well as secondary breaks because it is the limiting heatup transient. The analyses were performed using NOTRUMP for the first hour, followed by a 7-hour TREAT run. The results were extrapolated beyond 8 hours. Since the staff had not approved the TREAT code for LOCA analyses, it requested justification for its use including conformance with applicable 10 CFR 50, Appendix K requirements. In WCAP-11232, the applicant provided this justification including a description of the TREAT

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models and a comparison between TREAT and NOTRUMP results. This is further discussed below. It should be noted that the TREAT analyses comply with the Appendix K requirements regarding use of 1.2 times American Nuclear Society Standard ANS 5-1971 decay heat. Other Appendix K requirements pertain to swelling and rupture, thermal parameters, and blowdown phenomena, which are not pertinent to the analyses in the letter dated September 30,1986, since the reactor water level remains above the top of the active fuel at all times.

The 1.5-in.-break LOCA analysis assumes that the break occurs in loop 2. The analysis showed reactor trip at 102% power caused by low RCS pressure at 46 seconds, coincident with the loss of offsite power (LOOP) and failure of emergency bus A (the most severe single active failure). Safety injection into loop 3 commenced at 440 seconds, when RCS pressure decreased below 1500 psi (HHSI pump shutoff head). Auxiliary feedwater (AFW) injection to SG 2 and SG 3 commenced at 106 seconds. Cooldown at 50°F/hour was initiated by the operator at 1500 seconds by opening the SG 2 and SG 3 power-operated relief valves (PORVs). Accumulator injection into loops 1 and 3 began at 6200 seconds. Automatic switchover to cold-leg recirculation was initiated at 12,500 seconds after 350,000 gallons of refueling water storage tank liquid had been utilized The HHSI pump was stopped at about 20,000 seconds, and the LHSI pump was subsequently started. Operation of three of six RCFCs was assumed. The liquid level remained above the top of the active fuel at all times. The total amount of AFW used at the end of 12 hours was estimated to be less than 100,000 gallons. Thus the 1.5-in.-break case is not limiting for AFST depletion.

The 0.7-in.-break LOCA analysis makes assumptions similar to those for the 1.5-in.-break case, that is, the break occurs in loop 2. The reactor is at 102% power when tripped. LOOP and loss of emergency bus A occur at 200 seconds. AFW is initiated at 260 seconds. SI injection commences at 2200 seconds, at which time the operator also initiates cooldown at 50°F/hour, by using the SG 2 and SG 3 PORVs. In response to decreasing pressurizer level, one pressurizer PORV is opened at 8000 seconds to restore level and is operated several times. The reactor vessel liquid level remains above the top of the active fuel at all times. The HHSI pump was stopped at 19,000 seconds. RCS injection from the LHSI pump started at 22,900 seconds. The transient was stopped at 25,500 seconds. At this time RHR entry conditions had been reached. Also, at this time the AFST depletion was 133,500 gallons (30% of the minimum usable inventory) and the RWST depletion was 168,000 gallons (about 50% of the "switchover volume").

The feedline break analysis in the letter dated September 30, 1986 differs from the analysis presented in Section 15.2.8 of the SER in that it was performed using the Appendix K modeling assumptions for decay heat, i.e., using 120% ANS 5-1971 decay heat, while the analysis in Section 15.2.8 was performed using 102% of ANS 5.1-1979 decay heat. The latter is acceptable for non-LOCA accidents. The break is assumed to occur at SG 1. Reactor trip resulting from low-low SG level, and concurrent LOOP occur at 30 seconds. AFW flow to only SG 2 is assumed. Operator action is assumed at 30 minutes to isolate AFW to the faulted SG. The initial RCS heatup caused the pressurizer safety valves to cycle until the SG 2 PORV was opened. At 40 minutes the operator opened the SG 2 PORV to stabilize RCS temperature. At 10,800 seconds AFW cross-connect valves were opened to admit AFW to SG 3. Cooldown was started at 14,560 seconds utilizing the SG 2 and SG 3 PORVs, and was limited to less than 25°F/hour. At 65,000 seconds (18 hours) the head vent was opened to depressurize the RCS.

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The transient was terminated at 75,600 seconds (21 hours) at which time RHR entry conditions were reached.

The AFST depletion at this time was 396,000 gallons, leaving a usable margin of 49,000 gallons.. If ANS 5.1-1979 decay heat had been assumed, the AFST depletion would have been approximately 15% less, leaving a usable margin of about 100,000 gallons. As previously noted, this case bounds all secondary breaks and also isolable primary breaks since it is the limiting heatup transient.

TREAT Evaluation

The TREAT code, like the NOTRUMP code, was designed to simulate a thermal-hydraulic transient response in complex systems by using models of thermal-fluid behavior. However, the TREAT code is interactive and runs in real time with a fixed time step, whereas the NOTRUMP code runs in the batch mode and uses a variable time step. The NOTRUMP models for bubble rise, drift flux, and flooding correlations are more sophisticated than the TREAT models, and NOTRUMP uses a single nonequilibrium node for steam generator modeling, whereas TREAT uses multiple nodes to represent the steam generator secondary system. The applicant provided the staff with a comparison analysis, for a small-break LOCA, between the TREAT code and the NOTRUMP code for the first 3600 seconds of the accident in WCAP-11232. The review of this analysis indicated that there was a significant divergence at the end of the 1-hour comparison between the NOTRUMP and TREAT results for the SG tube mixture level, hot-leg and core flowrates, and cold-leg fluid temperature. The applicant responded to the staff's concern by submitting a new comparison analysis in which the TREAT analysis was extended an additional 600 seconds. The new analysis showed that most of the differences in thermal-hydraulic behavior can be tied to the differences between the TREAT and NOTRUMP break flowrate. Although TREAT and NOTRUMP both use the same break flow correlations, because of slightly higher predicted RCS pressure and subcooling at the break location, NOTRUMP predicts a slightly higher break flow than TREAT between 500 and 3000 seconds in the transient. This caused the SG tubes to drain later and natural circulation to continue for a longer period of time in the TREAT analysis. After 3200 seconds, the TREAT break flow begins to exhibit the same behavior NOTRUMP had shown between 2200 and 3000 seconds. The transient results presented in the TREAT/NOTRUMP comparison in WCAP-11232 which appear to diverge at the end of 1 hour can be traced to differences in the modeling technique, which resulted in a time shift in the resulting transient behavior as predicted by the TREAT code. Therefore, on the basis of comparison results reported in WCAP-11232 and the additional extended TREAT analysis results, it has been demonstrated that TREAT is applicable for analyzing the small-break-LOCA recovery transient, with long-term cooling, which does not uncover the core.

Conclusion

The staff concludes that the applicant has provided analyses of ECCS performance for short-term mitigation for a spectrum of small-break LOCAs utilizing NOTRUMP, an NRC-approved code, which demonstrate that the South Texas ECCS design meets 10 CFR 50.46. This also satisfies the requirements of TMI Action Plan Item II.K.3.31. The staff further concludes that the applicant has provided analyses for the long-term mitigation of small-break LOCAs, including post-LOCA cooldown, using acceptable codes, which demonstrate that the South Texas systems are adequately designed to mitigate this accident, providing the staff also concludes that the South Texas RHR pumps are designed to adequately function

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after being subjected to the postaccident environmental conditions resulting from a small-break LOCA or secondary break. Confirmatory Item 34 is therefore closed.

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APPENDIX A

CONTINUATION OF NRC STAFF RADIOLOGICAL REVIEW OF THE SOUTH TEXAS PROJECT

May 27, 1986*	Letter from applicant concerning the operability, maintenance, and testing of emergency lighting systems.
August 22, 1986*	Letter from applicant concerning revised loss-of-coolant accident analyses.
August 26, 1986*	Representatives from NRC and applicant meet in Bay City, Texas near the South Texas site. Site was visited to conduct the discussions and observe the demonstration as indicated in the agenda. (Summary issued October 7, 1986.)
August 28, 1986*	Letter from applicant concerning elimination of additional arbitrary intermediate breaks.
August 28, 1986*	Letter from applicant concerning preservice inspection (PSI) examination plan for component supports.
August 28, 1986*	Letter from applicant concerning relief request from Section XI requirements for PSI examination for cast stainless steel.
January 16, 1987	Letter to applicant requesting additional information on the procedures generation packages.
January 16, 1987	Letter to applicant concerning staff comments and request for additional information on certain pipe break criteria applied at South Texas.
January 20, 1987	Letter from applicant concerning final report on toxic gas detectors.
January 20, 1987	Letter from applicant transmitting the final report on toxic gas detectors.
January 21, 1987	Letter from applicant concerning applicability of Diablo Canyon natural circulation test--Confirmatory Item 11.
January 23, 1987	Letter from applicant concerning 1987 graded emergency preparedness exercise.

*Although the dates of these letters precede this continuation of chronology, they are included here because they respond to issues discussed in this supplement.

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January 26, 1987	Letter from applicant concerning revised boron dilution analysis for mode 5 (cold shutdown).
January 26, 1987	Letter from applicant concerning annotated revisions of Final Safety Analysis Report (FSAR) Section 9.1.3.
January 27, 1987	Letter from applicant concerning draft Revision 2 Technical Specifications.
January 27, 1987	Letter from applicant concerning Generic Letter 81-07 (control of heavy loads).
January 27-30, 1987	Representatives from NRC, staff consultants, and applicant meet in Bay City, Texas at South Texas site to conduct the following audits: electrical systems audit, instrumentation and control systems audit, safety parameter display system and detailed control room design review audits, and environmental equipment qualification audit. (Summary issued March 12, 1987.)
January 28, 1987	Letter from applicant transmitting draft Revision 2 Technical Specifications.
January 29, 1987	Letter from applicant concerning final report on calibration of measuring and testing equipment.
January 29, 1987	Letter from applicant transmitting the final report on ASME flexible hoses.
January 29, 1987	Letter to applicant transmitting the fourth audit report of the qualified display processing system.
January 30, 1987	Letter from applicant concerning Interim Security Plan for Fuel Storage, Revision 3.
January 30, 1987	Letter to applicant concerning fog monitoring program.
January 30, 1987	Letter from applicant concerning seismic analysis performed using N-411 damping.
January 30, 1987	Letter from applicant concerning emergency dc lighting systems--Confirmatory Item 20.
February 2, 1987	Letter from applicant transmitting justifications or specific data for some of the proposed technical specifications for South Texas in draft Revision 2 Technical Specifications.
February 3, 1987	Letter from applicant concerning personnel training and qualification plan.
February 5, 1987	Letter from applicant concerning annotated revisions with regard to alarms for letdown stop valve operation.

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February 5, 1987	Letter from applicant concerning safety-related instrument tubing program.
February 5, 1987	Letter from applicant concerning the operation and maintenance manual for the main cooling reservoir.
February 5, 1987	Letter from applicant concerning first interim report on liquidtight flexible conduit.
February 10, 1987	Representatives from NRC and applicant meet in Bethesda, Maryland to discuss postaccident operability time. (Summary letter from applicant dated March 9, 1987.)
February 11, 1987	Letter from applicant transmitting a response to staff comments on the procedures generation package.
February 11, 1987	Letter from applicant concerning numbers of senior reactor operators and reactor operators.
February 12, 1987	Letter from applicant concerning proof-and-review copy of the South Texas Unit 1 Technical Specifications.
February 13, 1987	Letter from applicant concerning annotated revisions with regard to active components and valves.
February 13, 1987	Letter to applicant transmitting 20 copies of SSER 2.
February 13, 1987	Letter from applicant concerning interim report on corrective action process.
February 13, 1987	Letter from applicant transmitting additional information (Open Item 16).
February 17, 1987	Letter from applicant concerning annotated FSAR revisions with regard to revised response time for certain radiation monitors.
February 18, 1987	Letter from applicant concerning final report on water damage to Unit 1 equipment.
February 18, 1987	Letter from applicant transmitting revised response to Office of Inspection and Enforcement IE Bulletin 77-07.
February 19, 1987	Letter from applicant concerning Class 1E non-Class 1E control circuit interfaces.
February 19, 1987	Letter from applicant concerning annotated FSAR revisions with regard to essential cooling water system.
February 19, 1987	Letter from applicant concerning revision to FSAR Table 3.11-1 on environmental conditions.
February 19, 1987	Letter from applicant concerning leak-before-break analysis of accumulator safety injection line.

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February 19, 1987	Letter from applicant concerning annotated revisions to FSAR Table 9.4-2.3.
February 19, 1987	Letter from applicant concerning Regulatory Guide 1.75 physical separation; Wyle test results (Open Item 9).
February 19, 1987	Letter from applicant concerning annotated FSAR revisions regarding the process and postaccident sampling systems.
February 19, 1987	Letter from applicant concerning reactor coolant system flow measurement uncertainty--request for withholding from public disclosure pursuant to 10 CFR 2.790.
February 20, 1987	Letter from applicant transmitting FSAR Amendment 57.
February 20, 1987	Letter from applicant concerning meteorological data comparison--Confirmatory Item 1.
February 20, 1987	Letter from applicant concerning revised system component evaluation worksheets for environmental qualification audit.
February 23, 1987	Letter from applicant transmitting responses to questions resulting from the Seismic Qualification Review Team/Pump and Valve Operability Review Team (SQRT/PVORT) and environmental qualification audits.
February 23, 1987	Letter from applicant concerning applicability of Diablo Canyon natural circulation test--Confirmatory Item 11.
February 24, 1987	Letter from applicant concerning camera-ready figures for proof-and-review Technical Specifications.
February 24, 1987	Letter from applicant transmitting additional information on the diesel generator fuel oil piping vibration testing.
February 24, 1987	Letter from applicant concerning deletion of Technical Specification surveillance requirements for turbine overspeed protection.
February 24, 1987	Letter from applicant concerning annotated FSAR revisions with regard to turbine generator building heating, ventilation, and air conditioning (HVAC) system and the electrical auxiliary building/technical support center HVAC system.
February 24, 1987	Letter from applicant concerning annotated revisions with regard to reactor vessel and internals modeling.
February 25, 1987	Letter from applicant concerning operator examination materials.
February 25, 1987	Letter from applicant concerning April 8, 1987 graded emergency preparedness exercise scenario.

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February 26 87	Letter from applicant transmitting the final report on diesel air start header filter bowls.
February 26, 1987	Letter from applicant concerning annotated revisions with regard to instrument and service air system.
February 26, 1987	Letter from applicant concerning annotated revisions of FSAR Section 9.1.3.
February 26, 1987	Letter from applicant concerning annotated revisions with regard to the radionuclide inventory of liquid waste processing system tanks.
February 26, 1987	Letter from applicant concerning the changes in referencing demineralized water fill source.
February 26, 1987	Letter from applicant transmitting an application for construction permit amendments regarding primary coolant loop piping compliance with General Design Criterion 4.
February 26, 1987	Letter from applicant concerning annotated FSAR revisions with regard to the qualified display processing system (QPDS).
February 27, 1987	Letter from applicant transmitting supplementary information for the equipment qualification submittals.
February 27, 1987	Letter from applicant responding to request for additional information with regard to IE Bulletin 85-03.
February 27, 1987	Letter to applicant requesting additional information on elimination of arbitrary intermediate pipe breaks at South Texas.
February 27, 1987	Letter to applicant requesting additional information on the containment spray system for South Texas Units 1 and 2.
February 27, 1987	Letter from applicant transmitting an advance copy of Fire Hazards Analysis Report Amendment 5.
March 2, 1987	Letter from applicant transmitting responses to NRC staff questions regarding NUREG-0737, Item II.D.1.
March 2, 1987	Letter from applicant concerning annotated FSAR revisions with regard to fuel handling building HVAC system.
March 2, 1987	Letter from applicant concerning annotated revision of FSAR Section 9.3.3.4.
March 2, 1987	Letter from applicant concerning annotated FSAR revisions with regard to pipe break criteria.

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March 2, 1987	Letter from applicant concerning annotated revision to the responses to NRC Questions 210.55N and 210.60N (Confirmatory Item 6).
March 2, 1987	Letter from applicant concerning annotated FSAR revisions with regard to the miscellaneous buildings HVAC system.
March 3-5, 1987	Site visit and audit of South Texas Project organization. (For summary see Sections 13.1 and 13.5 of this supplement.)
March 4, 1987	Letter from applicant concerning annotated FSAR revisions to the response to NRC Question 280.09N regarding fire protection and ventilation systems.
March 5, 1987	Letter from applicant transmitting responses to questions resulting from the environmental qualification audit.
March 5, 1987	Letter from applicant concerning annotated revision to FSAR Table 3.5-9 regarding tornado missiles.
March 5, 1987	Letter from applicant transmitting response to Notice of Deviation (498/8633-01)
March 6, 1987	Letter from applicant transmitting responses to NRC questions with regard to NUREG-0737, Item II.D.1.
March 6, 1987	Letter from applicant concerning process control program.
March 6, 1987	Letter from applicant concerning FSAR change to reflect as-built auxiliary feedwater pump performance.
March 9, 1987	Letter from applicant concerning emergency plan--revision dated March 6, 1987.
March 9, 1987	Letter from applicant concerning second interim report on corrective action process.
March 9, 1987	Letter from applicant concerning final report on use of General Electric fuse pull boxes.
March 9, 1987	Letter from applicant concerning annotated FSAR revisions regarding pipe break--isolation valve cubicle subcompartment analysis.
March 9, 1987	Letter from applicant concerning clarification on the essential cooling pond temperature at transient analysis initiation.
March 9, 1987	Letter from applicant transmitting minutes of the meeting with NRC staff on postaccident operability time on February 10, 1987.

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March 9, 1987	Letter from applicant concerning Question 480.28 (part c)--effect of debris particles during recirculation.
March 11, 1987	Letter from applicant concerning Appendix R and Final Hazards Analysis Report (FHAR).
March 11, 1987	Letter from applicant transmitting responses to electrical systems audit items.
March 11, 1987	Letter from applicant concerning annotated FSAR revisions regarding structural analysis.
March 11, 1987	Letter from applicant concerning changes to FSAR Section 14.2 in Amendment 56.
March 12, 1987	Letter from applicant concerning security personnel training and qualification plan.
March 13, 1987	Letter from applicant concerning interim report on dc contacts used in inductive circuits.
March 13, 1987	Letter from applicant concerning proof-and-review Technical Specifications.
March 13, 1987	Letter from applicant concerning final report on liquid-tight flexible conduit.
March 13, 1987	Letter from applicant concerning leak-before-break analysis of accumulator safety injection line.
March 13, 1987	Letter from applicant concerning final report on Telemecanique J13 four-pole relays.
March 13, 1987	Letter from applicant concerning responses to instrumentation and control audit items.
March 13, 1987	Letter from applicant concerning shift operating experience.
March 13, 1987	Letter from applicant transmitting responses to control room design review audit items.
March 16, 1987	Letter from applicant requesting an exemption for criticality monitors under 10 CFR 50.
March 16, 1987	Letter from applicant concerning proof-and-review Technical Specification comments.
March 16, 1987	Letter from applicant concerning proof-and-review Technical Specifications and Offsite Dose Calculation Manual.
March 18, 1987	Letter from applicant concerning first interim report on electrical splices using Raychem heat shrink.

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March 18, 1987	Letter from applicant concerning Final Environmental Statement impingement/entrainment monitoring program.
March 18, 1987	Letter from applicant concerning fog monitoring program.
March 18, 1987	Representatives from NRC and applicant meet in Bethesda, Maryland to discuss the fire protection audit. This meeting was followed up by audit on March 30 through April 3, 1987. (For summary see Section 9.5.1 of this supplement.)
March 19, 1987	Letter from applicant concerning submittal of Supplement 1 to the QDPS Verification and Validation Program Final Report.
March 19, 1987	Letter from applicant concerning revision to the component cooling water pump logic diagram.
March 19, 1987	Letter from applicant concerning responses to safety parameter display system audit items.
March 23, 1987	Letter from applicant concerning FHAR Amendment 5.
March 23, 1987	Letter from applicant responding to Inspection Report 50-498/86-42, 50-499/86-42.
March 23, 1987	Letter from applicant concerning quality assurance program for the design and construction phase of the South Texas Project.
March 25, 1987	Letter to applicant concerning Confirmatory Item 20.
March 26, 1987	Letter from applicant concerning camera-ready figures for proof-and-review Technical Specifications.
March 26, 1987	Letter from applicant concerning perservice/inservice inspection Relief Request RR-ENG-06--pressurizer support attachment weld.
March 26, 1987	Letter from applicant concerning annotated FSAR revisions regarding the incorporation of high density spent fuel racks.
March 26, 1987	Letter from applicant concerning large-break loss-of-coolant-accident analysis.
March 26, 1987	Letter from applicant concerning annotated FSAR revisions regarding the diesel generator cooling water system.
March 26, 1987	Letter from applicant concerning annotated FSAR revisions regarding the listing of active components (pumps) and valves--closeout of PVORT audit item.

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March 26, 1987	Letter from applicant concerning annotated FSAR revisions regarding radiation monitoring instrumentation.
March 26, 1987	Letter from applicant concerning main cooling reservoir.
March 26, 1987	Letter from applicant concerning annotated FSAR revision regarding the auxiliary fuel oil storage and transfer system.
March 26, 1987	Letter from applicant concerning annotated FSAR revision regarding the equipment and floor drain system.
March 26, 1987	Letter from applicant concerning annotated FSAR revisions regarding the component cooling water system.
March 26, 1987	Letter from applicant concerning FSAR Table 6.2.1.2-1.
March 26, 1987	Letter from applicant concerning revised FSAR sections related to fire protection.
March 26, 1987	Letter from applicant concerning election of Vice President, Nuclear Operations.
March 27, 1987	Letter from applicant concerning 125 V dc control power for 13.8-kV switchgear.
March 27, 1987	Letter from applicant concerning FSAR Amendment 58.
March 27, 1987	Letter from applicant concerning final report on the nylon and Tefzel ties on Class 1E cables.
March 27, 1987	Letter from applicant concerning use of fuses as isolation devices.
March 27, 1987	Letter to applicant concerning a request for additional information on General Design Criterion 4 exemption request with regard to pressurizer surge line.
March 27, 1987	Letter from applicant concerning fault current values used in Regulatory Guide 1.75 testing.
March 27, 1987	Letter from applicant concerning updated information on Appendix R and FHAR.
March 27, 1987	Letter from applicant concerning emergency preparedness appraisal.
March 30, 1987	Letter from applicant concerning natural circulation (Confirmatory Item 11) and long-term cooling (Open Item 16).

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March 30, 1987	Representatives from NRC and applicant meet in Bethesda, Maryland to discuss the applicant's submittal regarding changes to methodology with respect to structural analysis. (For summary see Section 3.8.6 of the supplement.)
March 30, 1987	Letter from applicant concerning Sondex decommissioning.
March 31, 1987	Letter from applicant concerning pump and valve inservice test program.
March 31, 1987	Letter from applicant concerning "Engineering Assurance Program--Summary Report" and "Categorization of Third Party and Independent Technical Assessment Action Items."
March 31, 1987	Letter from applicant concerning preservice inspection examination plan for steam generator tubes (Unit 2).
April 1, 1987	Letter from applicant concerning FSAR changes with regard to air sampling and monitoring instrumentation and effluent, process, and area radiation monitor test.
April 1, 1987	Letter to applicant concerning partial approval of Revision 3 to the South Texas Project Interim Security Plan for Fuel Storage.
April 1, 1987	Letter from applicant concerning preservice inspection summary report for Class 1 and 2 pressure retaining components (Open Item 5).
April 2, 1987	Letter from applicant concerning the emergency plan.
April 8, 1987	Letter from applicant concerning final report on corrective action process.
April 8, 1987	Letter from applicant concerning audit conducted on March 30 through April 3, 1987.
April 8, 1987	Letter from applicant concerning elimination of arbitrary intermediate breaks.
April 8, 1987	Letter from applicant concerning responses to Regulatory Guide 1.75 testing and electrical audit items.
April 8, 1987	Letter from applicant concerning final report on resistance temperature detector time response.
April 9, 1987	Letter from applicant concerning information on component cooling water containment isolation.
April 10, 1987	Letter from applicant concerning Raychem penetration splices.
April 13, 1987	Letter from applicant concerning revisions to FSAR Table 3.12.1.

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April 13, 1987	Letter from applicant concerning responses to instrumentation and control audit items.
April 13, 1987	Letter from applicant concerning FSAR revisions with regard to the diesel general building and turbine generator building HVAC system.
April 13, 1987	Letter from applicant concerning response to NRC staff comments on seismic II/I quality assurance program.
April 13, 1987	Letter from applicant concerning revisions to FSAR Sections 9.5.3.2.3 and 9.5.3.3.
April 13, 1987	Letter from applicant concerning FSAR revisions with regard to responses to Questions 480.19N and 022.02.
April 13, 1987	Letter from applicant concerning revisions to the notes to FSAR Figure 5.1-5.
April 13, 1987	Letter from applicant concerning revisions to FSAR Table 2.5.C-1.
April 13, 1987	Letter from applicant concerning revisions to FSAR Section 1.5.1 with regard to verification tests (17x17 fuel assembly).
April 13, 1987	Letter from applicant concerning revisions to FSAR Section 3.9.1.4.5 with regard to analysis of primary components.
April 13, 1987	Letter from applicant concerning FSAR revisions with regard to Questions 211.01N and 440.23N.
April 13, 1987	Letter from applicant concerning revisions to FSAR Section 15.4.1.2.
April 13, 1987	Letter from applicant concerning FSAR revisions with regard to the response to Question 430.20N.
April 13, 1987	Letter from applicant concerning revisions to FSAR Figure 6.2.4-1 with regard to containment penetrations.
April 13, 1987	Letter from applicant concerning annotated revision to the response to NRC staff Question 122.1.
April 13, 1987	Letter from applicant concerning revisions to FSAR Table 9.2.2-2 with regard to component cooling water system water chemistry.
April 14, 1987	Letter from applicant concerning responses to questions resulting from the PVORT and environmental audits.
April 14, 1987	Letter from applicant concerning revisions to FSAR Section 6.3 with regard to emergency core cooling system.

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April 14, 1987	Letter from applicant concerning revisions to FSAR Section 3.8.1.4 with regard to design and analysis procedures (concrete containment).
April 14, 1987	Letter from applicant concerning revisions to FSAR Table 6.1-4.
April 14, 1987	Letter from applicant concerning FSAR revisions with regard to Question 241.05--essential cooling pond seepage analysis.
April 14, 1987	Letter from applicant concerning revisions to FSAR Section 9.2.1.1 with regard to auxiliary cooling water system.
April 14, 1987	Letter from applicant concerning revisions to FSAR Section 3.9 with regard to mechanical systems and components.
April 14, 1987	Letter from applicant concerning revisions to FSAR Section 6.2.2 with regard to reactor containment fan coolers.
April 14, 1987	Letter from applicant concerning revisions to FSAR Sections 9.5.5 and 9.5.6.
April 14, 1987	Letter from applicant concerning FSAR revisions regarding water chemistry.
April 14, 1987	Letter from applicant concerning revisions to FSAR Section 2.5.6 with regard to embankment settlement.
April 14, 1987	Letter from applicant concerning revisions to FSAR Section 8.3.1.4.4.5.
April 14, 1987	Letter from applicant concerning FSAR revisions regarding diesel generator fuel oil system.
April 14, 1987	Letter from applicant concerning revisions to FSAR Chapters 2.4 and 2.5 with regard to responses to questions.
April 15, 1987	Letter to applicant concerning request for additional information relative to the General Design Criterion 4 exemption request on the accumulator line.
April 17, 1987	Letter from applicant concerning Appendix R audit of March 30-April 3, 1987.
April 20, 1987	Letter to applicant concerning request for additional information on environmental qualification of safety-related mechanical equipment.
April 28, 1987	Letter from applicant concerning emergency lighting systems, Confirmatory Item 20.

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APPENDIX B

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APPENDIX D

ACRONYMS AND INITIALISMS

AE	architect-engineer
AFST	auxiliary feedwater storage tank
AFW	auxiliary feedwater
AIB	arbitrary intermediate break
ALS	aluminum sheathed
ANS	American Nuclear Society
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
ASP	auxiliary shutdown panel
BMI	bottom-mounted instrumentation
BNL	Brookhaven National Laboratory
B&O	Bulletins and Orders
BOP	balance of plant
BRC	Bureau of Radiation Control
BTP	branch technical position
B&W	Babcock and Wilcox
CCP	centrigugal charging pump
CCW	component cooling water
C_D	discharge coefficient
CES	Cooper Energy System
CFMS	configuration management system
CFR	Code of Federal Regulations
COA	City of Austin
CPL	Central Power and Light Company
CPS	City Public Service Board of San Antonio
CRDM	control rod drive mechanism
CS	copper sheathed
CSS	containment spray system
CUF	cumulative usage factor
CVCS	chemical and volume control system
DAC	distance amplitude correction
DEM	Division of Emergency Management
DG	diesel generator
DOE	U.S. Department of Energy
EAB	electrical auxiliary building
EAL	emergency action level
EBS	emergency broadcast system
ECCS	emergency core cooling system
ECP	essential cooling pond
ECW	essential cooling water

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EI	Energy Incorporated
EOC	emergency operations center
EPIP	emergency plan implementing procedure
EPZ	emergency planning zone
ERF	emergency response facility
ERFDADS	emergency response facility data acquisition and display system
ESF	engineered safety feature
ETE	evacuation time estimate
FAT	factory acceptance tests
FEMA	Federal Emergency Management Agency
FHAR	Final Hazards Analysis Report
FM	Factory Mutual
FSAR	Final Safety Analysis Report
GA	General Atomic Company
GDC	general design criterion(a)
HHSI	high head safety injection
HL&P	Houston Lighting and Power Company
HPI	high pressure injection
HVAC	heating, ventilation, and air conditioning
IE	Office of Inspection and Enforcement
IEEE	Institute of Electrical and Electronics Engineers
INEL	Idaho National Engineering Laboratories
INPO	Institute of Nuclear Power Operations
ISI	inservice inspection
LBB	leak before break
LHSI	low head safety injection
LOCA	loss-of-coolant accident
LOOP	loss of offsite power
MAB	mechanical auxiliary building
MCF	maximum credible fault
MSIV	main steam isolation valve
msl	mean sea level
MT	magnetic particle
NFPA	National Fire Protection Association
NRC	U.S. Nuclear Regulatory Commission
NSSS	nuclear steam supply system
OSC	operations support center
PCT	peak cladding temperature
PORC	Plant Operations Review Committee
PORV	power-operated relief valve
PROM	programmable read only memory
PSI	preservice inspection
PSMS	plant safety monitoring system
PVORT	Pump and Valve Operability Review Team
QDPS	qualified display processing system

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RAI	request for additional information
RCFC	reactor containment fan cooler
RCP	reactor coolant pump
RCS	reactor coolant system
RG	regulatory guide
RHR	residual heat removal
RMW	reactor makeup water
RPV	reactor pressure vessel
RTD	resistance temperature detector
RV	relief valve
RVUH	reactor vessel upper head
SER	Safety Evaluation Report
SG	steam generator
SGWLCS	steam generator water level compensation system
SI	safety injection
SPDS	safety parameter display system
SQRT	Seismic Qualification Review Team
SRP	Standard Review Plan
SSER	Supplement to Safety Evaluation Report
STS	Standard Technical Specifications
SV	safety valve
TSC	technical support center
UH	upper head
UL	Underwriters Laboratories, Inc.
UT	ultrasonic
V&V	verification and validation
WOG	Westinghouse Owners Group

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APPENDIX E

NRC STAFF CONTRIBUTORS AND CONSULTANTS

This Supplemental Safety Evaluation Report is the product of NRC staff and its consultants. The NRC staff members listed below were principal contributors to this report.

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*Reflects reorganizational changes that occurred in April 1987.

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APPENDIX V

PRESERVICE INSPECTION RELIEF REQUEST EVALUATION

I INTRODUCTION

This section was prepared with the technical assistance of U.S. Department of Energy contractors from the Idaho National Engineering Laboratory.

For nuclear power facilities whose construction permits were issued on or after July 1, 1974, 10 CFR 50.55a(g)(3) specifies that components shall meet the preservice examination requirements set forth in editions and addenda of Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) applied to the construction of the particular component. The provisions of 10 CFR 50.55a(g)(3) also state that components (including supports) may meet the requirements set forth in subsequent editions and addenda of this Code which are incorporated by reference in 10 CFR 50.55a(b) subject to the limitations and modifications listed therein.

Requests for relief from the ASME Code Section XI requirements which the applicant has determined are impracticable for systems and components at South Texas Unit 1 were contained in the submittals dated August 28 and December 9, 1986. These relief requests were all supported by information pursuant to 10 CFR 50.55a(a)(3). Therefore, the staff evaluation consisted of reviewing the submittals to the requirements of the applicable Code edition and addenda and determining if relief from the Code requirements was justified.

II TECHNICAL REVIEW CONSIDERATIONS

A. The construction permit for South Texas Unit 1 was issued on December 22, 1975. In accordance with 10 CFR 50.55a(g)(3), components (including supports) that are classified as ASME Code Class 1 and 2 have been designed and provided with access to enable the performance of required preservice examinations.

B. Verification of as-built structural integrity of the primary pressure boundary is not dependent on the Section XI preservice examination. The applicable construction codes to which the primary pressure boundary was fabricated contain examination and testing requirements that by themselves provide the necessary assurance that the pressure boundary components are capable of performing safely under all operating conditions reviewed in the FSAR and described in the plant design specification. As a part of these examinations, all of the primary pressure boundary full penetration welds were volumetrically examined (radiographed) and the system was subjected to hydrostatic pressure tests.

In the case of South Texas Unit 1, a large percentage of the preservice examination required by the ASME Code was performed. Failure to perform a

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100% preservice examination of the welds identified below will not affect the assurance of initial structural integrity.

C. The intent of a preservice examination is to establish a reference or baseline before the initial operation of the facility. The results of subsequent inservice examinations can then be compared with the original condition to determine whether changes have occurred If the inservice inspection results show no change from the original condition, no action is required. In the case where baseline data are not available, all flaws must be treated as new flaws and evaluated accordingly. Section XI of the ASME Code contains acceptance standards that may be used as the basis for evaluating the acceptability of such flaws.

D. Other benefits of the preservice examination include providing redundant or alternative volumetric examination of the primary pressure boundary using a test method different from that employed during the component fabrication. Successful performance of the preservice examination also demonstrates that the welds so examined are capable of subsequent inservice examination using a similar test method.

E. In some instances where the required preservice examinations were not performed to the full extent specified by the applicable ASME Code, the staff may require that these examinations or supplemental examinations be conducted as a part of the inservice inspection program. Requiring supplemental examinations to be performed at this time would result in hardships or unusual difficulties without a compensating increase in the level of quality or safety. The performance of supplemental examinations, such as surface examinations, in areas where volumetric examination is difficult will be more meaningful after a period of operation. Acceptable preoperational integrity has already been established by similar ASME Code Section III fabrication examinations.

In cases where parts of the required examination areas cannot be effectively examined because of a combination of component design or current examination technique limitations, the development of new or improved examination techniques will continue to be evaluated. As improvements in these areas are achieved, the staff will require that these new techniques be made a part of the inservice examination requirements for the components or welds that received a limited preservice examination.

Several of the preservice inspection relief requests involve examination of less than the required volume of a specific weld. The inservice inspection (ISI) program is based on the examination of a representative sample of welds to detect generic service-induced degradation. If the welds identified in the PSI relief requests are required to be examined again, the possibility of augmented inservice inspection will be evaluated during review of the applicant's initial 10-year ISI program. An augmented program may include increasing the extent and/or frequency of examination of accessible welds.

III EVALUATION OF RELIEF REQUESTS

The applicant requested relief from specific preservice inspection requirements in submittals dated August 28 and December 9, 1986. All of these relief

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requests were supported by information pursuant to 10 CFR 50.55a(a)(3). On the basis of the information submitted by the applicant and the staff's review of the design, geometry, and materials of construction of the components, certain preservice inspection requirements of ASME Code Section XI have been determined to be impracticable to perform. The applicant has demonstrated that either (1) the proposed alternative would provide an acceptable level of quality and safety or (2) compliance with the specified requirements of this section would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, pursuant to 10 CFR 50.55a(a)(3), conclusions that these preservice requirements are impracticable are justified as follows. Unless otherwise stated, references to the Code refer to Section XI of the ASME Code, 1980 Edition including Addenda through Winter 1981 (80W81).

A. Relief Request RR-ENG-01, Class 2 Pipe Welds and Supports in Open-Ended Portions of the Containment Spray System

Code Requirement: 10 CFR 50.55a(b)(2)(iv) requires that containment heat removal systems be examined during PSI/ISI and that the extent of examination be determined in accordance with the rules of IWC-1220; Table IWC-2520, Examination Categories C-F and C-G; and IWC-2411 of the 1974 Edition through the Summer 1975 Addenda (74S75) of ASME Code Section XI. IWC-1220(b) permits exemption of systems from examination that do not operate during normal reactor operating conditions. Although the containment spray system (CSS) qualifies for exemption under this criterion, exemption of the entire CSS would be contrary to 10 CFR 50.55a(b)(2)(iv). Therefore, IWC-1220(b) was not applied to the CSS, and the applicant committed to perform augmented examinations.

Subsection IWF-2510 (80W81) requires that component supports selected for examination shall be the supports of those components that are required to be examined under IWC.

Code Relief Request: Relief is requested from performing surface examinations on approximately 68 circumferential piping welds including portions of adjacent longitudinal welds on piping and fittings, and visual examinations of approximately 56 piping supports.

Reason for Request: Winter 1983 Addenda of Section XI and Code Case N-408 specifically allow components to be exempted from examination if they are "piping and other components of any size beyond the last shutoff valve in open-ended portions of systems that do not contain water during normal plant operating conditions." Since the CSS components for which relief is requested may be exempted from inservice examination under current Section XI rules and/or Code Case N-408, the preservice examination of these components is of little practical value, especially in light of the lack of adverse service conditions to initiate and propagate flaws.

The applicant has committed to perform augmented volumetric examination on a representative sample of piping welds in the nonexempt boundary (based on the exemption criterion of 4-in. and less nominal pipe size) of the containment spray suction and discharge piping up to the containment isolation valves in each train. The selection of piping welds for volumetric examination will be based on the criteria of Code Case N-408 regardless of pipe wall thickness. Additionally, volumetric and surface

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examinations will be performed on the first circumferential piping weld beyond the containment isolation valve in one of the three trains. This augmented examination in conjunction with the volumetric examinations already performed under the existing PSI Program Plan will result in a volumetric sampling rate of 19.5% of the nonexempt CSS pipe welds at South Texas Unit 1.

In addition, the applicant reported that the initial structural integrity of all of the subject piping welds has been verified by the Code Section III radiographic examinations performed during fabrication.

Staff Evaluation: The staff has reviewed the applicant's August 28, 1986 submittal of Relief Request RR-ENG-01 and concluded that, on the basis of 10 CFR 50.55a(b)(2)(iv), the augmented sampling rate of 19.5% of the non-exempt CSS pipe welds, and Code Case N-408, which is approved for use as specified in Regulatory Guide 1.147, Revision 5, relief is not required.

B. Relief Request RR-ENG-02, Examination Category C-F, Items C5.11 and C5.12, Class 2 Pressure Retaining Welds in the Safety Injection (SI) System

Code Requirement: Section XI, Table IWC-2500-1, Examination Category C-F, Items C5.11 and C5.12 require a 100% surface examination on longitudinal and circumferential pressure retaining piping welds with 1/2-in. and less nominal wall thickness as defined by Figure IWC-2500-7.

Code Relief Request: Relief is requested from performing the Code-required surface examination on one circumferential butt weld (16-SI-1301-27) and the adjacent longitudinal pipe weld (16-SI-1301-27LU) in train C of the 16-in. SI recirculation sump piping (two welds total).

Reason for Request: Each of the three SI sump suction lines contains an inaccessible circumferential weld located within the guard pipe at the containment penetration. The guard pipe does not permit access to the flued head-to-process pipe weld for the required surface examination. One of the three inaccessible welds is required to be examined for PSI. Weld number 27 of train C (16-SI-1301-27) was selected for PSI examination.

The applicant reports that the SI sump suction piping of each train between the sump and the normally closed containment isolation valve is "open-ended" piping that will not contain water under normal plant operating conditions, and that such piping may be exempted from examination under the rules of Code Case N-408. Therefore, the applicant does not intend to examine the welds in the open-ended portion of the SI system, including the subject weld, for ISI.

In addition, the applicant reports that the initial structural integrity of the subject welds has been verified by the Code Section III fabrication examinations performed during construction.

Staff Evaluation: The staff has reviewed the above information and concluded that, in order to complete the Code-required surface examination, the flued head/guard pipe assembly would have to be redesigned. The staff also notes that the Code-required surface examinations which met the requirements of Section XI were performed on welds of similar configuration

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using the same inspection techniques, equipment, and procedures as the subject welds. Since these welds will be exposed to the same operating and environmental conditions as the inspected welds, a reasonable assurance of the structural integrity of the welds for which relief is requested has been attained.

On the basis of the above review, and the fact that the subject welds will not be included as part of the ISI program, the staff has concluded that the Section III fabrication examinations provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

C. Relief Request RR-ENG-03, Examination Category C-B, Item C2.22, Steam Generator, Main Steam Nozzle, Examination of Inside-Radius Section

Code Requirement: Section XI, Table IWC-2500-1, Examination Category C-B, Item C2.22 requires a 100% volumetric examination on nozzle inside-radius sections, on Class 2 nozzles in vessels with greater than 1/2-in. nominal wall thicknesses, as defined by Figure IWC-2500-4.

Code Relief Request: Relief is requested from performing the Code-required volumetric examination on four main steam nozzle inside-radius sections.

Reason for Request: In the case of the subject steam generator main steam nozzles, the nozzle is a one-piece forging containing a set of seven holes bored parallel to the nozzle centerline. A flow restrictor is installed in each of these holes. Since the ligaments between the holes distribute the stresses throughout the nozzle forging, there is no high-stress inside-radius section for the subject nozzles.

Staff Evaluation: The subject main steam nozzles on the steam generators were designed without a nozzle inside-radius section; therefore, the Code-required volumetric examination could not be performed. Compliance with the exact Section XI requirements would delay the startup of the plant in order to redesign the nozzles. The staff concludes that the Code Section III fabrication examinations performed during construction and the system hydrostatic tests provide an acceptable level of preservice structural integrity and that compliance with the exact Section XI requirements would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

NOTE: Relief request RR-ENG-04 has been divided into three parts, which are evaluated in paragraphs D through F below.

D. Relief Request RR-ENG-04 (Part 1), Examination Category B-A, Pressure Retaining Welds in the Reactor Pressure Vessel

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-A, Items B1.11 and B1.12 require a 100% volumetric examination on reactor pressure vessel (RPV) shell welds as defined by Figures IWB-2500-1 and IWB-2500-2; Items B1.21 and B1.22 require a 100% volumetric examination on

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RPV head welds as defined by Figure IWB-2500-3; Item B1.30 requires a 100% volumetric examination on the RPV shell-to-flange weld as defined by Figure IWB-2500-4; and Item B1.40 requires both a 100% surface and volumetric examination on the RPV head-to-flange weld as defined by Figure IWB-2500-5.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination on the following RPV welds:

Weld no.	Weld description	Code item no.
RPV1-101-141	Lower head-to-shell weld	B1.11
RPV1-101-122A	Upper shell longitudinal weld	B1.12
RPV1-101-122B	Upper shell longitudinal weld	B1.12
RPV1-101-122C	Upper shell longitudinal weld	B1.12
RPV1-103-101	Torus-to-dome weld	B1.21
RPV1-102-151	Lower head dollar plate weld	B1.21
RPV1-101-154A	Lower head meridional weld	B1.22
RPV1-101-154B	Lower head meridional weld	B1.22
RPV1-101-154C	Lower head meridional weld	B1.22
RPV1-101-154D	Lower head meridional weld	B1.22
RPV1-101-121	Upper shell-to-flange weld	B1.30
RPV1-101-101	Torus-to-flange weld	B1.40

Reason for Request: The following information is supported by figures showing the specific welds with the described interferences, and tables describing the ultrasonic examination angles with respect to the percent of volume examined with each.

Lower Head-to-Shell Weld: Volumetric examination was limited because of interference from the core support and antirotation lugs.

Upper Shell Longitudinal Welds: Volumetric examination was limited because of interference from adjacent or intersecting nozzles.

Torus-to-Dome Weld: Volumetric examination was limited because of interference from the insulation support ring and from the head lifting lugs.

Lower Head Dollar Plate Weld and Lower Head Meridional Welds: Volumetric examination was limited because of interference from the in-core instrumentation tubes.

Upper Shell-to-Flange Weld: Volumetric examination was limited because of interference from the flange taper on one side and the outlet nozzle integral extensions on the other side.

Torus-to-Flange Weld: Volumetric examination was limited on the flange side because of the flange configuration.

The applicant also reports that, in addition to the limited Section XI volumetric examination, all of the above subject welds received radiographic, ultrasonic, and surface examinations during fabrication to meet the requirements of ASME Code Section III.

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Staff Evaluation: The staff has reviewed the applicant's submittal, which included a listing of the welds for which relief is being requested, the weld design, the specific obstruction which limits the examination, and the percentage of the Code-required examination that was completed.

On the basis of the above review, the staff has concluded that a significant percentage of the Code-required examination has been performed and that the reactor pressure vessel would have to be redesigned in order to complete the remainder. The staff concludes that the limited Section XI volumetric examination and the Section III fabrication examinations, along with the hydrostatic test, provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

E. Relief Request RR-ENG-04 (Part 2), Examination Category B-D, Item B3.90, Reactor Pressure Vessel Nozzle-to-Vessel Welds, and Item B3.100, Nozzle Inside-Radius Section

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-D, Items B3.90 and B3.100 require a 100% volumetric examination on the reactor pressure vessel nozzle-to-vessel welds and nozzle inside-radius sections as defined by Figure IWB-2500-7.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination on the reactor pressure vessel inlet and outlet nozzles.

Reason for Request: The inlet and outlet nozzle-to-vessel welds were examined from the vessel shell and from the nozzle bore. Transverse examinations performed from the vessel wall were limited on the nozzle forging side of the weld because of the nozzle configuration. Nozzle configuration also shadowed the straight-beam and angle-beam examination performed from the nozzle bores. The applicant also states that the Code-defined nozzle inner-radius sections were nevertheless covered adequately using 50/70-degree search units in the nozzle bores and on the blend itself in the case of the inlet nozzles.

The above information is supported by figures showing the nozzle-to-vessel welds with the above-described interferences, and tables describing the ultrasonic examination angles with respect to the percent of volume examined with each.

The applicant also reports that, in addition to limited Section XI volumetric examination, the above subject welds received radiographic, ultrasonic, and surface examinations during fabrication to meet the requirements of ASME Code Section III.

Staff Evaluation: The staff has reviewed the applicant's submittal, including the figures and tables showing the limitations to examination and the percentage of the Code-required examination that was completed.

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On the basis of the above review, the staff has concluded that a significant percentage of the Code-required examination has been performed and that the reactor pressure vessel inlet and outlet nozzles would have to be redesigned in order to complete the remainder. The staff concludes that the limited Section XI volumetric examination and the Section III fabrication examinations, along with the hydrostatic test, provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

F. Relief Request RR-ENG-04 (Part 3), Examination Category B-G-1, Item B6.10 Reactor Pressure Vessel Closure Head Nuts, and Item B6.30, Studs

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-G-1, Item B6.10 requires a surface examination on the reactor vessel closure head nuts, and Item B6.30 requires a surface and volumetric examination on the reactor vessel closure studs (when removed) as defined by Figure IWB-2500-12.

Code Relief Request: Relief is requested from performing 100% of the Code-required surface examination on closure nuts 1A through 31A, 34A through 37A, 32B, 33B, and 38SB.

Relief is also requested from performing 100% of the Code-required volumetric examination on closure studs 1A through 38A.

Reason for Request:

RPV Closure Nuts: Magnetic particle (MT) examination was performed on all surfaces except the threaded portion, which could not be examined because of MT yoke access requirements. Ultrasonic (UT) examination was performed as a supplemental examination of the threaded area. However, the UT coverage (from the outer-diameter surface) was limited to 91% of the threaded area because of spanner wrench slots.

RPV Closure Studs: The UT volumetric examination was limited because of the configuration of the Roto-Lok lugs. However, the applicant reports that the examination volume is in accordance with Code Case N-307-1, and that 95% of the Code-required volumetric examination was completed.

In addition to the above PSI examinations, the applicant reported that the subject nuts and studs also received both UT and MT examinations during fabrication.

Staff Evaluation: The staff has reviewed the applicant's submittal and concluded that a significant percentage (91-95%) of the Code-required examination has been performed, and that this examination in conjunction with the fabrication examinations provides an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

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NOTE: Relief request RR-ENG-05 has been divided into 10 parts, which are evaluated in paragraphs G through P below.

G. Relief Request RR-ENG-05 (Part 1), Examination Category B-B, Pressure Retaining Welds in the Pressurizer and Steam Generator

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-B, Items B2.11 and B2.12 require a 100% volumetric examination on pressurizer shell-to-head welds as defined by Figures IWB-2500-1 and IWB-2500-2; and Items B2.31 and B2.40 require a 100% volumetric examination on steam generator head welds and tubesheet-to-head welds as defined by Figures IWB-2500-3 and IWB-2500-6, respectively.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination on the following welds:

Pressurizer Vessel Welds

Code item no.	Weld no.	Total coverage
B2.11	PRZ-1-C1	91%
B2.11	PRZ-1-C4	99%
B2.11	PRZ-1-C7	92%
B2.12	PRZ-1-L1	86%

Steam Generator Vessel Welds

Code item no.	Weld no.	Total coverage
B2.31	SG-1A-SR1	58%
B2.31	SG-1B-SR1	59%
B2.31	SG-1C-SR1	58%
B2.31	SG-1D-SR1	58%
B2.40	SG-1A-SR2	61%
B2.40	SG-1B-SR2	60%
B2.40	SG-1C-SR2	61%
B2.40	SG-1D-SR2	60%

Reason for Request:

Pressurizer: Volumetric examination of the subject pressurizer welds was limited because of the proximity of permanent pipe supports, 3/4-in. instrumentation lines, trunnions, welded lugs, support skirts, and permanent insulation support rings. The applicant also reported that all of the subject welds received the ASME Code-required Section III radiographic and liquid penetrant examinations during fabrication.

Steam Generator: Volumetric examination of the subject steam generator welds was limited because of the support ring configuration and/or the proximity of inlet and outlet nozzle welds. The applicant also reported that the subject welds received the ASME Code-required Section III radiographic and magnetic particle examinations during fabrication.

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Staff Evaluation: The staff has reviewed the information in the applicant's submittal and concluded that a significant percentage of the Code-required examination has been performed on the subject welds and that the pressurizer and steam generators would have to be redesigned in order to complete the remainder. The Section III fabrication examinations and the limited Section XI volumetric examination provide an acceptable level of preservice structural integrity. Compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

H. Relief Request RR-ENG-05 (Part 2), Examination Category B-D, Full Penetration Nozzle Welds in the Pressurizer and Steam Generators

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-D, Item B3.110 requires a 100% volumetric examination on pressurizer nozzle-to-vessel welds and Item B3.130 requires a 100% volumetric examination on steam generator (primary side) nozzle-to-vessel welds. These volumetric examinations are to be as defined by Figure IWB-2500-7.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination on the following nozzle welds:

Pressurizer Nozzle Weld

Weld no.	Total coverage
PRZ-1-N4C	99%

Steam Generator Nozzle Welds

Weld no.	Total coverage
SG-1A-IN	78%
SG-1A-ON	79%
SG-1B-IN	79%
SG-1B-ON	79%
SG-1C-IN	79%
SG-1C-ON	79%
SG-1D-IN	78%
SG-1D-ON	79%

Reason for Request:

Pressurizer: Volumetric examination of the subject weld was limited because of the proximity of a 1-in. line above the examination area. The applicant also reported that the subject weld received the ASME Code-required Section III radiographic and liquid penetrant examination during fabrication.

Steam Generators: Volumetric examination of the subject nozzle welds was limited from the head side because of the proximity of weld SR-1 (head-to-support ring weld). The applicant also reported that the subject welds

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received the ASME Code-required Section III radiographic and magnetic particle examination during fabrication.

Staff Evaluation: The staff has reviewed the information in the applicant's submittal and concluded that a significant percentage of the Code-required examination has been performed on the subject nozzle welds and that the pressurizer and steam generators would have to be redesigned in order to complete the remainder. The Section III fabrication examinations and the limited Section XI volumetric examination provide an acceptable level of preservice structural integrity. Compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

I. Relief Request RR-ENG-05 (Part 3), Examination Category B-F, Class 1 Pressure Retaining Dissimilar Metal Welds

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-F, Item B5.40 requires a 100% surface and volumetric examination on pressurizer nozzle-to-safe end butt welds 4-in. and greater nominal pipe sizes; Item B5.130 also requires a 100% surface and volumetric examination on dissimilar metal piping welds 4-in. and greater nominal pipe size. These examinations shall be as defined by Figure IWB-2500-8.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination on the following dissimilar metal welds:

Pressurizer Nozzle-to-Safe End Welds

Weld no.	Total coverage
PRZ-1-N1-SE	97%
PRZ-1-N2-SE	95%
PRZ-1-N3-SE	99.5%
PRZ-1-N4A-SE	94%
PRZ-1-N4B-SE	98%
PRZ-1-N4C-SE	96%

Reactor Coolant Loop Dissimilar Metal Piping Welds

Weld no.	Total coverage
31-RC-1102-1	85%
31-RC-1202-1	77%
31-RC-1302-1	86%
31-RC-1402-1	83%
29-RC-1101-5	67%
29-RC-1201-5	68%
29-RC-1301-5	85%
29-RC-1401-4	84%

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Reason for Request:

Pressurizer: Volumetric examination of the subject pressurizer nozzle-to-safe end welds was limited from the nozzle side because of the nozzle configuration and/or proximity of permanent insulation support lugs.

Reactor Coolant System: Volumetric examination of the subject reactor coolant system dissimilar metal nozzle-to-elbow welds was limited from the nozzle side because of the nozzle configuration and from the elbow side because of the weld configuration and the size of the search unit.

The applicant also reported that all of the subject pressurizer and reactor coolant system welds received the ASME Code-required Section III radiographic and liquid penetrant examinations during fabrication.

Staff Evaluation: The staff has reviewed the information in the applicant's submittal and concluded that a significant percentage of the Code-required examination has been performed on the subject welds and that the pressurizer and reactor coolant system would have to be redesigned in order to complete the remainder. The Section III fabrication examinations and the limited Section XI volumetric examination provide an acceptable level of preservice structural integrity. Compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

J. Relief Request RR-ENG-05 (Part 4), Examination Category B-H, Item B8.20, Pressurizer Integrally Welded Attachments

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-H, Item B8.20 requires a 100% surface or volumetric examination as defined by Figures IWB-2500-13, IWB-2500-14, or IWB-2500-15.

Code Relief Request: Relief is requested from performing 7% of the Code-required surface examination on the following eight pressurizer support brackets: 1A, 1B, 2A, 2B, 3A, 3B, 4A, and 4B.

Reason for Request: The applicant reported that 7% of the Code-required surface examination could not be completed because of the proximity of a permanent support frame.

Staff Evaluation: The staff has reviewed the information in the applicant's submittal and concluded that a significant percentage of the Code-required examination has been performed on the subject welds and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

K. Relief Request RR-ENG-05 (Part 5), Examination Category B-J, Pressure Retaining Branch Connection and Piping Welds in Class 1 Piping

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-J, Item B9.11 requires a 100% surface and volumetric examination on Class 1 pressure retaining circumferential piping welds 4-in. and greater nominal

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pipe size as defined by Figure IWB-2500-8; Item B9.31 requires a 100% surface and volumetric examination on Class 1 pressure retaining branch pipe connection welds 4-in. and greater nominal pipe size as defined by Figures IWB-2500-9, IWB-2500-10, and IWB-2500-11.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric or surface examination on the following Class 1 pressure retaining welds in piping:

Residual Heat Removal System Piping Welds

Weld no.	Total coverage
12-RH-1101-16	99% (vol)
8-RH-1112-2	99% (vol)
8-RH-1212-1	99% (vol)
8-RH-1212-2	98% (vol)

Reactor Coolant System Piping Circumferential Welds

Weld no.	Total coverage
31-RC-1102-2	69% (vol)
31-RC-1102-3	92% (vol)
31-RC-1102-4	83% (vol)
31-RC-1102-8	83% (vol)
31-RC-1102-9	53% (vol)
31-RC-1202-2	90% (vol)
31-RC-1202-3	91% (vol)
31-RC-1202-4	93% (vol)
31-RC-1202-8	91% (vol)
31-RC-1202-9	52% (vol)
31-RC-1302-2	83% (vol)
31-RC-1302-3	89% (vol)
31-RC-1302-4	83% (vol)
31-RC-1302-8	83% (vol)
31-RC-1302-9	82% (vol)
31-RC-1402-2	83% (vol)
31-RC-1402-3	83% (vol)
31-RC-1402-4	83% (vol)
31-RC-1402-8	83% (vol)
31-RC-1402-9	54% (vol)
29-RC-1101-4	90% (vol)
29-RC-1201-4	88% (vol)
29-RC-1401-3	92% (vol)
27.5-RC-1203-1	96% (vol)
8-RC-1114-1	98% (vol)
8-RC-1214-1	97% (vol)
6-RC-1015-2	95% (vol)
6-RC-1015-11	97% (vol)
6-RC-1015-12	99% (sur)
4-RC-1320-6	96% (vol)

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Reactor Coolant System Branch Connection Welds

Weld no.	Total coverage
31-RC-1302-7	85% (vol)
29-RC-1101-2	56% (vol)
29-RC-1101-3	45% (vol)
29-RC-1201-2	56% (vol)
29-RC-1201-3	45% (vol)
29-RC-1301-2	56% (vol)
29-RC-1301-3	45% (vol)
29-RC-1401-2	45% (vol)
27.5-RC-1103-3	85% (vol)
27.5-RC-1103-4	85% (vol)
27.5-RC-1303-3	85% (vol)
27.5-RC-1403-3	85% (vol)
27.5-RC-1403-4	85% (vol)

Safety Injection System Piping Welds

Weld no.	Total coverage
8-SI-1108-2	97% (vol)
8-SI-1108-3	97% (vol)
8-SI-1208-2	97% (vol)
8-SI-1208-3	97% (vol)
8-SI-1327-2	99% (vol)
8-SI-1327-3	98% (vol)
6-SI-1211-1	99% (vol)
6-SI-1211-2	90% (vol)
6-SI-1327-1	96% (vol)

Reason for Request:

Piping Circumferential Welds: All of the above pressure retaining circumferential welds in the reactor coolant, residual heat removal, and safety injection systems are either fitting-to-fitting, fitting-to-component, fitting-to-pipe, or component-to-pipe welds. These welds all have limited access because of the weld configuration and the size of the search unit.

Branch Connection Welds: All of the above branch connection welds in the reactor coolant system received limited volumetric examination because of the component configuration.

Attachment RR-ENG-05-01 to the applicant's request for relief contains the detailed examination limitations for each of the subject welds and also lists the ASME Code Section III fabrication examinations that were completed during construction for each of the subject welds.

Staff Evaluation: The staff has reviewed the information in the applicant's submittal and concluded that a significant percentage of the Code-required examination has been performed on the subject welds and that the reactor

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coolant, residual heat removal, and safety injection systems would have to be redesigned in order to complete the remainder. The Section III fabrication examinations and the limited Section XI volumetric examination provide an acceptable level of preservice structural integrity. Compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

L. Relief Request RR-ENG-05 (Part 6), Examination Category C-A, Pressure Retaining Welds in Class 2 Pressure Vessels

Code Requirement: Section XI, Table IWC-2500-1, Examination Category C-A, Items C1.10, C1.20, and C1.30 require a 100% volumetric examination on shell circumferential welds at gross structural discontinuities, head circumferential welds, and tubesheet-to-shell welds on Class 2 pressure vessels. In the case of multiple vessels of similar design, size, and service, the required examinations may be limited to one vessel or distributed among the vessels. These examinations shall be as defined in Figures IWC-2500-1 and IWC-2500-2.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination on the following Class 2 vessel welds:

Steam Generator Shell Welds

Weld no.	Total coverage
SG-1A-S5	99.8%
SG-1B-S3	99%
SG-1B-S5	99.8%
SG-1C-S3	99%
SG-1C-S5	99.9%
SG-1D-S3	99.6%
SG-1D-S5	99.8%

Steam Generator Head Welds

Weld no.	Total coverage
SG-1A-S7	99.8%
SG-1B-S7	99.9%
SG-1C-S7	99.9%
SG-1D-S7	99.9%

Steam Generator Tubesheet-to-Shell Welds

Weld no.	Total coverage
SG-1A-S1	91%
SG-1B-S1	91%
SG-1C-S1	92%
SG-1D-S1	91%

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Residual Heat Removal Heat Exchanger Shell Welds

Weld no.	Total coverage
RHAHRS-1A-S2	94%
RHAHRS-1B-S2	93%
RHAHRS-1C-S2	94%

Excess Letdown Heat Exchanger Shell Weld

Weld no.	Total coverage
CSAHEL-1A-S1	98%

Reactor Coolant Filter Shell Welds

Weld no.	Total coverage
CSFLRC-1A-S1	49%
CSFLRC-1A-S2	63%
CSFLRC-1B-S1	49%
CSFLRC-1B-S2	63%

Reason for Request:

Steam Generators: The steam generator shell welds received a limited ultrasonic examination because of the proximity of auxiliary feedwater nozzles and trunnions or the lower lateral support ring beam. The steam generator head welds received a limited ultrasonic examination from the head side because of the proximity of welded lugs. The steam generator tubesheet-to-shell welds received a limited ultrasonic examination because of the proximity of instrumentation lines and inspection holes. The applicant also reported that all of the subject steam generator welds received the ASME Code-required Section III radiographic and magnetic particle examinations during fabrication.

Residual Heat Removal Heat Exchanger Shell Welds: The subject welds received a limited ultrasonic examination because of the flange configuration. The applicant reported that these welds received the ASME Code-required Section III radiographic examination during fabrication.

Excess Letdown Heat Exchanger Shell Weld: The subject weld received a limited ultrasonic examination from the head side of the weld because of the head configuration and from the flange side because of the proximity of the flange bolting. The applicant reported that this weld received the ASME Code-required radiographic examination during fabrication.

Reactor Coolant Filter Shell Welds: The inlet-to-shell welds (S1 welds) received a limited ultrasonic examination because of geometric interferences caused by welded support legs and the proximity of a branch connection and outlet nozzle. The shell-to-head welds (S2 welds) received a limited ultrasonic examination because of the head configuration and the proximity of closure brackets and name plates. The applicant reported that these

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welds received the ASME Code-required Section III liquid penetrant examination during fabrication.

Staff Evaluation: The staff has reviewed the information in the applicant's submittal and concluded that a significant percentage of the Code-required examination has been performed on the subject welds and that the steam generators, residual heat removal heat exchangers, excess letdown heat exchanger, and reactor coolant filters would have to be redesigned in order to complete the remainder. The Section III fabrication examinations and the limited Section XI volumetric examination provide an acceptable level of preservice structural integrity. Compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

M. Relief Request RR-ENG-05 (Part 7), Examination Category C-B, Pressure Retaining Nozzle Welds in Class 2 Vessels

Code Requirement: Section XI, Table IWC-2500-1, Examination Category C-B, Item C2.21 requires a 100% surface and volumetric examination on nozzle-to-shell (or head) welds in Class 2 vessels greater than 1/2-in. nominal thickness as defined by Figure IWC-2500-4.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination on the following nozzle welds:

Regenerative Heat Exchanger Nozzle Welds

Weld no.	Total coverage
CSAHRG-1A-S1	95%
CSAHRG-1A-S8	95%
CSAHRG-1A-S9	69%
CSAHRG-1A-S10	62%

Residual Heat Removal Heat Exchanger Nozzle Welds

Weld no.	Total coverage
RHAHRS-1A-NA	57%
RHAHRS-1A-NB	57%
RHAHRS-1B-NA	57%
RHAHRS-1B-NB	57%
RHAHRS-1C-NA	56%
RHAHRS-1C-NB	56%

Reason for Request:

Regenerative Heat Exchanger Nozzle Welds: The subject welds received a limited ultrasonic examination because of the proximity of branch connections and/or the configuration of the nozzle welds. The applicant reported that all of these nozzle welds received the ASME Code-required Section III radiographic examination during fabrication.

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Residual Heat Removal Heat Exchanger Nozzle Welds: The subject welds received a limited ultrasonic examination because of the nozzle weld geometry. The applicant reported that all of these nozzle welds received the ASME Code-required Section III radiographic examination during fabrication.

Staff Evaluation: The staff has reviewed the information in the applicant's submittal and concluded that a significant percentage of the Code-required examination has been performed on the subject welds and that the regenerative heat exchanger nozzles and the residual heat removal heat exchanger nozzles would have to be redesigned in order to complete the remainder. The Section III fabrication examinations and the limited Section XI volumetric examination provide an acceptable level of preservice structural integrity. Compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

N. Relief Request RR-ENG-05 (Part 8), Examination Category C-C, Item C3.20, Integrally Welded Attachments on Class 2 Piping

Code Requirement: Section XI, Table IWC-2500-1, Examination Category C-C, Item C3.20 requires a 100% surface examination on integrally welded attachments to Class 2 piping as defined by Figure IWC-2500-5.

NOTE: The applicant also committed to an augmented volumetric examination as these welds are part of the high-energy fluid system piping in the break exclusion zone.

Code Relief Request: Relief is requested from performing 100% of the Code-required surface and/or augmented required volumetric examination on the following Class 2 integrally welded pipe lugs:

Class 2 Feedwater System Pipe Lugs

		Coverage	
Line no.	Weld no.	Surface	Volumetric
18-FW-1029	1PL1-1PL8	57%	82%
18-FW-1029	1PL9-1PL10	N/A	94%
18-FW-1030	IPL1-1PL8	57%	82%
18-FW-1030	IPL9-1PL10	N/A	94%
18-FW-1031	IPL1-1PL8	57%	82%
18-FW-1031	IPL9-1PL10	N/A	94%
18-FW-1032	IPL1-1PL8	57%	82%
18-FW-1032	IPL9-1PL10	N/A	94%

Class 2 Main Steam System Pipe Lugs

		Coverage	
Line no.	Weld no.	Surface	Volumetric
30-MS-1001	27PL1-27PL8	55%	82%
30-MS-1001	28PL1-28PL2	N/A	94%
30-MS-1002	25PL1-25PL8	55%	82%

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Class 2 Main Steam System Pipe Lugs (Continued)

Line no.	Weld no.	Coverage Surface	Coverage Volumetric
30-MS-1002	26PL1-26PL2	N/A	94%
30-MS-1003	26PL1-26PL8	55%	82%
30-MS-1003	27PL1-27PL2	N/A	94%
30-MS-1004	26PL1-26PL8	55%	82%
30-MS-1004	27PL1-27PL2	N/A	94%

Reason for Request: All of the subject Class 2 integrally welded pipe lugs received a limited ultrasonic and magnetic particle examination because of the pipe lug configurations. The applicant reported that all of the subject integrally welded pipe lugs received a magnetic particle and/or liquid penetrant examination during fabrication as required by ASME Code Section III.

Staff Evaluation: The staff has reviewed the information in the applicant's submittals including the fabrication drawings showing areas of restricted access and concluded that a significant percentage of the Code-required examination has been performed on the subject welds and that the integrally welded attachments would have to be redesigned in order to complete the remainder. The Section III fabrication examinations, the limited Section XI surface examination, and the limited augmented volumetric examination provide an acceptable level of preservice structural integrity. Compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

O. Relief Request RR-ENG-05 (Part 9), Examination Category C-F, Pressure Retaining Welds in Class 2 Piping

Code Requirement: Section XI, Table IWC-2500-1, Examination Category C-F, Item C5.11 requires a 100% surface examination on Class 2 pressure retaining piping welds with 1/2-in. or less nominal wall thicknesses; and Items C5.21 and C5.22 require both a 100% surface and volumetric examination on Class 2 pressure retaining piping welds with greater than 1/2-in. nominal wall thicknesses. These examinations shall be as defined by Figure IWC-2500-7.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric and/or surface examination on the following Class 2 pressure retaining piping welds:

Residual Heat Removal System

Line no.	Weld no.	Coverage Surface	Coverage Volumetric
12-RH-1202	4	100%	95%
12-RH-1302	12	98%	100%
12-RH-1303	4	100%	96%
12-RH-1111	5	100%	95%

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Safety Injection System

Line no.	Weld no.	Coverage Surface	Coverage Volumetric
16-SI-1101	5	100%	86%
16-SI-1201	5	100%	89%
16-SI-1301	1	100%	84%
6-SI-1325	11	100%	94%
6-SI-1326	6	100%	98%

Main Steam System

Line no.	Weld no.	Coverage Surface	Coverage Volumetric
30-MS-1001	27	100%	85%
30-MS-1001	27LD	91%	94%
30-MS-1001	28LU	96%	97%
30-MS-1001	28LD	53%	74%
30-MS-1001	29LU	31%	61%
30-MS-1002	25LD	89%	93%
30-MS-1002	26LD	53%	75%
30-MS-1002	27LU	31%	63%
30-MS-1003	26LD	91%	94%
30-MS-1003	27LD	53%	75%
30-MS-1003	28LU	31%	63%
30-MS-1004	24LD	100%	99%
30-MS-1004	26LD	91%	94%
30-MS-1004	27LD	53%	75%
30-MS-1004	28LU	31%	63%

Reason for Request: The applicant reported that the subject longitudinal welds received a limited volumetric or surface examination because of interference caused by permanent pipe supports. The circumferential welds received a limited volumetric or surface examination because of geometric interferences caused by weld configurations (e.g., fitting-to-component, pipe-to-fitting, or pipe-to-component). The applicant also reported that all 15 of these welds received a radiographic examination during fabrication to meet the requirements of ASME Code Section III.

Staff Evaluation: The staff has reviewed the information submitted in the relief request, including the attachment that lists the welds for which relief is being requested, the weld configurations, the Code requirements, a brief description of the restriction, and the approximate percentage of the Code-required examination that was completed.

The staff also notes that complete examinations that met the requirements of ASME Code Section XI were performed on welds of similar configuration using the same inspection techniques, equipment, and procedures as those for the partially inspected or uninspected welds. Since the partially inspected or uninspected welds will be exposed to the same operating and environmental conditions as the inspected welds, a reasonable assurance of the structural integrity of the welds for which relief is requested has

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been attained. Also, all of the subject welds received the ASME Code Section III volumetric examination during fabrication.

On the basis of the above review, the staff has concluded that a significant portion of the Code-required preservice examinations has been completed and that these examinations, in conjunction with the Section III radiographic examination, provide an acceptable level of preservice structural integrity. Compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

P. Relief Request RR-ENG-05 (Part 10), Examination Category C-F, Class 2 Pressure Pertaining Welds in Carbon and Low Alloy Steel Piping

Code Requirement: Section XI (Winter 1983), Table IWC-2500-1, Examination Category C-F-2, Item C5.21 requires a 100% surface and volumetric examination on Class 2 pressure retaining welds in carbon and low alloy steel piping with nominal wall thicknesses greater than 1/5 in. in piping sizes 2-in., but less than 4-in., nominal pipe size. These examinations shall be performed as defined by Figure IWC-2500-7.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination on safety injection system weld 2-SI-1106-15.

Reason for Request: The applicant reported that the subject weld received 99% of the Code-required volumetric examination because of the proximity of a permanent pipe support. The applicant also reported that the subject weld received a radiographic examination during fabrication to meet the requirements of ASME Code Section III.

Staff Evaluation: On the basis of the above review, the staff has concluded that a significant percentage of the Code-required volumetric examination has been performed and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

IV CONCLUSIONS

On the basis of the foregoing, pursuant to 10 CFR 50.55a(a)(3), the staff has determined that certain Section XI-required preservice examinations are impracticable. The applicant has demonstrated that either (1) the proposed alternatives would provide an acceptable level of quality and safety or (2) compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

The staff technical evaluation has not identified any practical method by which the existing South Texas Unit 1 can meet all the specific preservice inspection requirements of Section XI of the ASME Code. Requiring compliance with all the exact Section XI-required inspections would delay the startup of the plant in orders to redesign a significant number of plant systems, obtain sufficient replacement components, install the new components, and repeat the preservice

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examination of these components. Examples of components that would require redesign to meet the specific preservice examination provisions are the reactor pressure vessel, the pressurizer, the steam generators, and a number of the piping and component support systems. Even after the redesign efforts, complete compliance with the preservice examination requirements probably could not be achieved. However, the as-built structural integrity of the existing primary pressure boundary has already been established by the construction code fabrication examinations.

On the basis of its review and evaluation, the staff concludes that the public interest is not served by imposing certain provisions of Section XI of the ASME Code that have been determined to be impracticable. Pursuant to 10 CFR 50.55a(a)(3), relief is allowed from these requirements which are impracticable to implement.

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14 ABSTRACT (200 words or less)

The Safety Evaluation Report issued in April 1986 provided the results of the NRC staff's review of the Houston Lighting and Power Company's application for licenses to operate the South Texas Project. The facility consists of two pressurized water nuclear reactors located in Matagorda County, Texas.

Supplement No. 1, issued in September 1986 updated the information contained in the Safety Evaluation Report and addressed the ACRS Report issued on June 10, 1986.

Supplement No. 2, issued in January 1987 addressed and resolved some of the outstanding issues remaining after issuance of the Safety Evaluation Report and Supplement No. 1.

This Supplement, No. 3 also addresses and resolves some of the outstanding issues remaining after issuance of the SER and Supplements 1 and 2.

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